



**CXHO PROJECT – OPERATION CANADIAN CRUDE (OCC)
SOURCE MODIFICATION APPLICATION
BP PRODUCTS NORTH AMERICA INC. – WHITING BUSINESS UNIT
WHITING, IN**

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1. EXECUTIVE SUMMARY

This document is an application for a Part 70 (Title V) Source Modification for the BP Products North America Inc. – Whiting Business Unit (BP Whiting) refinery located in Whiting, Indiana (Whiting Refinery). The Whiting Refinery is currently operating under a Title V Operating Permit (T089-6741-00453, effective on January 1, 2007) issued by the Indiana Department of Environmental Management (IDEM), as modified by Significant Permit Modification (SPM) 089-24068-00453 (issued on May 21, 2007) and SPM 089-24410-00453 (issued on June 19, 2007). An area map and overall plot plan for the Whiting Refinery are included in Appendix A.

1.1 PROPOSED MODIFICATIONS

In this Title V source modification application, BP Whiting is proposing to modify its Whiting Refinery source. In accordance with 326 IAC 2-7-10.5(c)(2), BP Whiting is submitting a combined preconstruction and operating application. However, BP requests that IDEM issue separate approvals for authorizing construction under significant source modification regulations and operation under significant permit modification regulations. The proposed modification includes the construction of various new emission units, the physical modification of some existing emission units and the shutdown of other existing emission units. In addition, the emissions from some emission units not being physically changed will be affected relative to what would be expected in the absence of the CXHO project. This project (also known as Operation Canadian Crude (OCC)) will allow the Whiting Refinery to modernize much of the refinery by shutting down and replacing older equipment and replacing it with new equipment. In addition, the Whiting Refinery will substitute Canadian eXtra Heavy Oil (CXHO) for a major portion of its existing crude slate. This CXHO material has substantially different characteristics and properties as compared to the majority of crude oils currently processed by the refinery. Processing increased amounts of the CXHO material requires modification of a number of process areas of the refinery.

1.2 PROJECT EMISSIONS AND NETTING SUMMARY

Tables 1.1 and 1.2 provide a summary of the net emissions changes associated with the CXHO project:

TABLE 1.1 PROJECT NET EMISSIONS INCREASES AND DECREASES FOR PSD APPLICABILITY

Pollutant	NO ₂	SO ₂	PM (filterable)	PM ₁₀ (filterable + condensable)*	CO	Sulfuric Acid Mist	Lead	Mercury	Beryllium	H ₂ S	Total Reduced Sulfur (TRS)
Net Emissions Increase (tpy)	-28.9	-39.4	-281.9	-41.6	-23.7	-113.4	-0.02	-0.001	-0.005	-15.9	-76.1
PSD Significance Level (tpy)	40	40	25	15	100	7.0	0.6	0.1**	0.0004**	10	10

*The current PM₁₀ SIP limits filterable PM₁₀ emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM₁₀ baseline based on the PM₁₀ SIP limits for PSD applicability purposes, which includes both filterable and condensable PM₁₀.

** Note that mercury and beryllium are not federally regulated pollutants for PSD purposes. Indiana regulations still list significant emission rates for these pollutants, however this part of the regulation is not SIP-approved by U.S. EPA, therefore this requirement is only state-enforceable.

TABLE 1.2 PROJECT NET EMISSIONS INCREASES AND DECREASES FOR NONATTAINMENT NSR APPLICABILITY

Pollutant	NO _x *	VOC (1-hour Standard)**	VOC (8-hour Standard)**	PM _{2.5} (filterable + condensable)
Net Emissions Increase (tpy)	-28.9	-14.8	-6.3	-41.6
Nonattainment NSR Significance Level (tpy)	40	25	40	15***

* Note that for the 1-hour ozone standard, NO_x is not considered an ozone precursor due to the waiver under Section 182(f) of the Clean Air Act. NO_x information is presented here only for the purposes of an evaluation with respect to the 8-hour ozone standard.

** VOC emissions are evaluated based on the NSR program effective under the 8-hour ozone standard as well as that previously effective under the 1-hour ozone standard (de minimis) for Lake County. Lake County is currently classified as “moderate” nonattainment for the 8-hour ozone standard. Lake County had previously been classified as “severe” nonattainment for the 1-hour ozone standard. The Court of Appeals for the District of Columbia Circuit has held that, under the anti-backsliding provisions in the Clean Air Act, the nonattainment new source review requirements that apply to severe nonattainment areas must be retained in areas, like Lake County, that were designated as severe nonattainment areas under the now-repealed 1-hour ozone standard, even though such areas are now designated as moderate nonattainment areas under the new 8-hour ozone standard. To date the Indiana SIP has not been revised to reflect this ruling and it is not clear whether the severe nonattainment NSR requirements may be applied in Lake County unless and until the SIP is actually revised. Nevertheless, to expedite the processing of this application, BP will demonstrate that the project would satisfy the serious nonattainment area NSR requirements even if they do currently apply.

***Based on interim guidance from US EPA, PM_{2.5} is evaluated based on significant emission rate thresholds established for PM₁₀. The current PM₁₀ SIP limits filterable PM₁₀ emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM₁₀ baseline based on the PM₁₀ SIP limits for PSD applicability purposes, which includes both filterable and condensable PM₁₀. PM_{2.5} emissions are not regulated by the Lake County PM₁₀ SIP, however, to be conservative, BP Whiting has adjusted PM_{2.5} baseline emissions in the same manner as for PM₁₀ emissions.

As indicated, given the controls incorporated into the design of the project and certain additional contemporaneous emission decreases that have been and will be achieved, the CXHO project is expected to result in a net emission decrease for all criteria pollutants.

2. CXHO PROJECT DESCRIPTION

2.1 OVERVIEW

The CXHO project proposes changes to the refinery to modernize the refinery and enable it to accommodate additional processing of CXHO. The current crude feed slate at the refinery is a mix of typical sweet and sour light crude oils along with some amounts of CXHO. The relative geographical proximity of the CXHO source to the Whiting Refinery makes it an attractive alternate feed to the current light crudes.

Due to the different physical and chemical properties between CXHO and the current crude slate (i.e., CXHO has a higher sulfur and coke content), a number of changes need to be made at the refinery to implement this project. Proposed changes include the addition of new units, the modification of many existing units, and the shutdown of some existing units.

As described in this section, many changes are needed to accommodate additional processing of CXHO. However, there are portions of the refinery that remain unaffected by the project. Since the CXHO project is a crude replacement project, there will be relatively few changes to the existing storage tanks, with the exception of a few new tanks detailed in Section 2.2.8. No new products will be distributed as a result of the CXHO project. The CXHO project will have no emissions impact on the asphalt production at the refinery. The refinery steam load is expected to remain at existing levels post the CXHO project including the steam that will be supplied by the new third party Hydrogen facility to be built for the project. However, during the contemporaneous period for the CXHO project, one of the refinery's Stanolind Power Stations (ISPS) will be shutdown and there is a potential for steam supplied by Whiting Clean Energy to be curtailed. Thus, it will be necessary for the refinery to build two new boilers to replace this steam load. A discussion of these new boilers is included in Appendix E.

The future configuration of equipment at the Whiting Refinery is depicted on the process flow diagrams provided in Appendix A. Figure A-1 (Appendix A) provides a simplified refinery-wide process overview of the future configuration. In addition, a complete set of IDEM source modification permit application forms is included in Appendix B.

2.2 NEW UNITS

A number of new units will be constructed at the Whiting Refinery as part of the CXHO project. These new units are detailed in the following sections:

2.2.1 NEW COKER (#2 COKER)

Under the proposed project, the existing coker, No. 11 B Pipe Still (Section D.2 of the Title V permit), will be shutdown and replaced with a new Coker having a capacity of 120,000 barrels per day. The new 6 drum Coker will process heavy crude fractions into coke in a similar manner to the current coker. The existing coker heaters, H-101, H-102, H-103, and H-104, detailed in Section D.2 of the Title V permit, having a maximum heat input capacity of 200 MMBtu/hr total, will be shutdown and replaced with three new heaters, H-201, H-202, and H-203. The new

heaters will each be rated at approximately 208 MMBtu/hr and NO_x emissions will be controlled with a combination of Low-NO_x Burners and selective catalytic reduction (SCR).

A simplified process flow diagram for the new coker is included in Appendix A as Figure A-2. The feed (resid) to the Coker is heated prior to being fed to the coke drums where it is thermally cracked to produce coke. Light hydrocarbon vapors are also produced during coking operations and they are routed from the top of the coke drum to a Fractionator. The overheads of the Fractionator are compressed to recover liquefied petroleum gas (LPG) and naphtha. The fuel gas from the vapor recovery section is further treated with amine to remove sulfur compounds. The resulting coker fuel gas has a very low sulfur content.

A new coke handling system will also be constructed to handle the coke produced from the new coker. The coke handling system will be designed to minimize emissions from the coke handling process. This handling system will include enclosed conveyors and be comprised of up to 10 transfer points in the main operating scenario. Coke handling operations will be expected to operate under this main operating scenario for 95% of operating hours annually. There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points, this operating scenario exists as a contingency for malfunctions that could occur within the enclosed coke handling system. Coke handling operations are expected to operate under this emergency operating scenario for no more than 5% of operating hours annually. These scenarios are detailed in the simplified process flow diagram included in Appendix A as Figures A-3a and A-3b. When the coking process is complete, coke is removed from the coke drums with a high pressure water spray and falls into a pit. The process is cycled between the six coke drums and coke is removed from two drums each cycle. The estimated production of the new coker is 6,000 tons/day of coke. The water saturated coke is moved from the pit to a temporary storage pile to dewater before it is moved by a bridge crane to a partially enclosed coke crusher. From the crusher the coke is conveyed in an enclosed conveyor to a transfer tower. The coke is then transferred using a series of enclosed conveyors to either the enclosed coke storage pile, or to the day bin for loadout into rail cars. Coke is also transferred from the enclosed storage pile using a series of enclosed conveyors back to the transfer tower, for transfer to the day bin for loadout into rail cars. From the day bin, coke will be loaded into rail cars using a telescopic chute to minimize particulate emissions. Particulate emissions from the storage and handling of the coke occur at various transfer points associated with the crusher, covered conveyors, day bin, and load out into the rail cars.

2.2.2 NEW HYDROGEN PLANT (3RD PARTY SMR)

In order to meet the increased CXHO-related hydrogen demand for the refinery, a new hydrogen plant using steam methane reforming (SMR) technology will be constructed.¹ Like the existing hydrogen plant (Section D.17 of the Title V permit), the new plant – designed to produce 200 million standard cubic feet (MMscf) of hydrogen per day – will produce 99+% pure hydrogen needed for the refinery hydrotreating processes. Additionally, the new hydrogen plant will

¹ Note that subsequently BP Whiting may arrange for a third party to construct and/or operate the proposed new hydrogen plant, however, BP is currently proposing to permit this source as part of the refinery and emissions from the new hydrogen plant will be included as part of this project.

provide steam to the refinery's new and existing operations. The new hydrogen plant includes two new process heaters, HU-1 and HU-2, each rated at 920 MMBtu/hr, fired by a combination of natural gas and pressure swing adsorption (PSA) off gas from the process. NO_x emissions from these new heaters will be controlled with a combination of Low-NO_x Burners and SCRs. A simplified process flow diagram for the new hydrogen plant is included in Appendix A as Figure A-4.

2.2.3 NEW GAS OIL HYDROTREATING UNIT

A new Gas Oil Hydrotreating Unit (GOHT) rated at 120,000 barrels per day is being installed to hydrotreat gas oil, which is the primary feed to the Fluid Catalytic Cracking Units (FCUs). The purpose of this low sulfur fuels GOHT unit is to reduce the sulfur and nitrogen content of the FCU feed and to improve the hydrogen content. This will enable the FCU to meet gasoline sulfur specifications and to improve FCU conversion yields.

The new GOHT unit will require two new process heaters, F-901A and F-901B, each rated at 47 MMBtu/hr. NO_x emissions from the process heaters will be controlled using Ultra-Low NO_x Burners. A simplified process flow diagram for the new GOHT unit is included in Appendix A as Figure A-5.

2.2.4 NEW 12 PIPE STILL HEATERS

Three new heaters will be installed as part of the existing 12 Pipe Still [12PS] (Section D.3 of the Title V permit). Two new 12PS atmospheric pipe still heaters, 12 PS H-101A, and H-101B, will be installed to replace the existing atmospheric pipe still heaters (i.e., H-1AN, H-1AS, and H-1CN, H-1B, H-1CX). The new atmospheric heaters will be rated at approximately 355 MMBtu/hr and NO_x emissions will be controlled using Ultra-Low NO_x Burners. As part of the CXHO project there will also be modifications made to the heat train and metallurgy upgrades to the existing atmospheric tower.

Additionally, a new 12PS vacuum heater, H-102, will be installed to replace the existing vacuum furnace, H-2. The new larger vacuum heater will provide the necessary duty for processing the atmospheric bottoms stream, the amount of which will increase given the characteristics of the heavier crude. The new vacuum heater will be rated at approximately 331 MMBtu/hr and NO_x emissions will be controlled using Ultra-Low NO_x Burners. Also, the existing vacuum tower will be replaced with a new vacuum tower as part of the CXHO project.

A simplified process flow diagram for the future configuration of 12PS is included in Appendix A as Figure A-6.

2.2.5 NEW COOLING TOWERS

New and modified equipment at the Refinery will require additional cooling water supply. BP proposes to meet this additional load requirement by constructing two new cooling towers. The new cooling towers (Cooling Towers 7 and 8) will have recirculation rates of approximately 21,000 gpm and 90,000 gpm, respectively. In addition, a new cooling tower (HU Cooling Tower) will be installed for the new Hydrogen unit with a recirculation rate of 14,000 gpm.

Particulate emissions from these cooling towers will be controlled by reducing liquid drift to 0.001% through the use of high efficiency liquid drift eliminators.

2.2.6 NEW FLARES

Three new flare stacks will be installed in support of the proposed CXHO project. One flare stack will be installed at the northern end of the refinery (GOHT Flare), primarily to support the new GOHT Unit. The second flare stack (South Flare) will be installed on the south side of the refinery, primarily to support the new Coker, the revamp of the existing 12 PS Unit and the Sulfur Recovery Complex. The third flare stack (HU Flare) will support the new hydrogen production unit.

Flare gases will be recovered from the new GOHT and South flares by a flare gas recovery system. The recovered gas streams will be sent to vapor recovery/treating area for removal of H₂S and heavy components before being utilized in the refinery fuel gas system. As such, emissions from these new flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines).

The HU flare will be operated with a water seal or nitrogen purge. As such there will be no purge gas emissions from the HU flare.

2.2.7 SULFUR RECOVERY COMPLEX

Due to the higher sulfur content of CXHO, the proposed project will increase the amount of sulfur that must be processed by the sulfur recovery complex (Section D.4 of the Title V permit). In order to meet this demand, BP Whiting will construct a number of lower sulfur fuels units including: two new Claus sulfur recovery trains (D & E), two new amine units (C & D), and two new sour water strippers to supplement the existing three Claus trains (A, B & C), two amine units (A & B), and the sour water stripper. The existing Beavon-Stretford tail gas unit (TGU) and Sodium Bisulfate (SBS) TGU will be shutdown and replaced with two new Claus Offgas Treaters (COTs). All five Claus sulfur recovery trains will be vented through one or both of the two new COTs. The two new COTs will be designed to provide 100% redundancy in the event that one of the units needs to be brought offline. Under standard operation with both COTs in service and without oxygen enrichment in the Claus trains, there will be excess tail gas processing capacity. A simplified process flow diagram for the future configuration of the sulfur recovery complex is included in Appendix A as Figure A-7.

2.2.8 NEW STORAGE TANKS

There will be eleven new storage tanks constructed as part of this project:

- one new Coker Feed Storage Tank,
- two new Sulfur Bulk Storage Tanks,
- a new Stormwater/Equalization Tank,
- seven new Brine Treatment Tanks,

The new Coker Feed Storage Tank (TK-6255) will be a 14,028,000 gallon-capacity fixed cone roof storage tanks, with an annual throughput of approximately 470 million gallons per year. The Coker Feed Storage Tank will store coker feed materials (resid) with a vapor pressure less than 0.5 psia.

The two Sulfur Bulk Storage Tanks (TK-SH-1 and TK-SH-2) will each be 1,008,000-gallon capacity fixed roof storage tanks. These tanks will store molten sulfur and will be controlled by a caustic scrubber. As such, there will only be a small amount of H₂S/total reduced sulfur (TRS) emitted from these tanks.

The new Stormwater/Equalization Tank (T-5052) will be a 11,676,000-gallon capacity, external floating roof tank, and will store oily wastewater. The vapor pressure of the material stored in this tank will be less than 0.5 psia.

The seven new Brine Treatment Tanks (TK-105A, TK-105B, TK-101, TK-102, TK-103, TK-104A, TK-104B) are all tanks to be constructed for treatment of the wastewater brine from the refinery's pipe still operations. Tanks TK-105A and 105B will be 867,000 gallon-capacity fixed roof tanks with an annual throughput of approximately 251 million gallons per year. Tanks TK-101, 102, and 103, will be 66,108 gallon capacity fixed roof storage tanks with an annual throughput of approximately 251 million gallons per year. Tanks 104A and 104B will be 89,922 gallon-capacity fixed roof tanks with an annual throughput of approximately 251 million gallons per year. All of these tanks will be closed vent and will be controlled to a 95% control efficiency for VOCs.

Refer to Appendix D for additional tank parameters and estimated emissions from these storage tanks as identified in the output files from U.S. EPA's Tanks 4.0 software.

2.2.9 NEW DISTILLATE HYDROTREATING UNIT HEATER

As part of the CXHO project, a new reactor will be installed in series with the two existing reactors at the Distillate Hydrotreating Unit (DHT) (section D.37 of the Title V permit). In addition, the existing DHT charge heater will be replaced by a new heater (B-601A) with a maximum heat input capacity of 41.9 MMBtu/hr. The new DHT heater stack will be equipped with a CO CEMS. New wash water injection pumps will be added and the size of the feed/effluent piping and product rundown will be increased. Also there will be upgrades to the metallurgy of the piping to and from the effluent condenser. A simplified process flow diagram for the future configuration of the DHT unit is included in Appendix A as Figure A-8.

2.2.10 NEW BOILERS

Two new boilers will be constructed to fulfill the steam demand needed for the refinery, including the CXHO Project, when the No. 1 Stanolind Power Station (1 SPS) is shutdown and to replace steam provided by Whiting Clean Energy in the event that the contract with Whiting Clean Energy expires and is not renewed. The boilers are discussed in further detail in Appendix E of this application.

2.2.11 SEWERS

New sewer systems will be constructed at various process areas as part of the CXHO project. These sewers will be controlled to meet 40 CFR 61 Subpart FF requirements.

2.3 MODIFIED EXISTING UNITS

In addition to the construction of new units, BP Whiting will be making physical modifications to a number of existing emission units as part of the CXHO project. These modifications are discussed below:

2.3.1 ISOMERIZATION UNIT (ISOM)

The main purpose of the front end section of the existing ISOM Unit (Section D.9 of the Title V permit) is to hydrotreat the feed to the unit (i.e., remove sulfur and nitrogen). In order to meet an anticipated increase in capacity and an increased level of nitrogen in the ISOM feed, a nitrogen guard bed will be installed in this front end section. In addition, the existing ISOM Heater (H-1) will be modified. The existing four burners in the F-3 box of the heater will be replaced with larger burners.

2.3.2 NO. 4 ULTRAFORMER (4UF)

Due to an increase in the naphtha feed rate to the existing 4UF (Section D.16 of the Title V permit), the CXHO project will include installation of an additional front end reactor, which will operate in parallel with the existing reactor (D-1). No modifications will be made to the furnaces at the unit.

2.3.3 FLUID CATALYTIC CRACKING UNIT 600 (FCU 600)

The existing FCU 600 (Section D.22 of the Title V permit) converts heavy gas oils into lighter products. In order to accommodate an increase in throughput at the FCU 600 as part of the CXHO project, BP Whiting will be making the following modifications:

- Modifications to the main fractionator tower, which includes replacing some trays with packing and modifying the bottom shed section,
- Replacing feed nozzles on the riser, and
- Repairing the reactor stripper.

Note that no physical changes are being made to the FCU 600 regenerator as part of this project. In addition to the modifications detailed above, the annual average outlet sulfur concentration from the FCU 600 will be reduced from the current limit of 50 ppmv (at 0% oxygen) to 37 ppmv (at 0% oxygen) SO₂ by hydrotreating all of the feed and using SO₂ reducing additives.

2.3.4 COOLING TOWERS

High efficiency liquid drift eliminators will be installed on the existing Cooling Towers 2, 3, and 4 to reduce particulate emissions. The proposed drift eliminators will reduce particulate emissions through reducing liquid drift to 0.001%. Additionally, the existing SBS Cooling Tower will be shutdown as part of the CXHO project.

2.3.5 MARINE DOCK LOADING

A Vapor Recovery Unit (or similar control such as a flameless oxidation system or low emissions flare) will be installed on the Marine Dock Loading (Section D.34 of the Title V permit) operations to control gasoline loading emissions. The Vapor Recovery Unit will control gasoline loading operations to 10 mg of VOC emissions per liter of product loaded. Conservatively, a potential associated increases in CO and NO_x emissions is accounted for as part of this project, as documented in Appendix C (Table C.61).

2.3.6 11C PIPE STILL (11C PS)

Ultra-Low NO_x Burners will be installed on the 11C PS Heater H-200 (Section D.1 of the Title V permit) as part of the CXHO project. This will result in a reduction in NO_x emissions from this heater.

2.3.7 AROMATICS RECOVERY UNIT (ARU)

Some minor modifications are being made at the ARU 200 section of the ARU (section D.10 of the Title V permit) to process lighter feed, which includes a new booster pump and some piping modifications. No modifications are being made to the furnaces at the ARU.

2.3.8 DISTILLATE DESULFURIZATION UNIT (DDU)

Some minor modifications are being made to the DDU (section D.18 of the Title V permit) to process CXHO feed, which include implementing continuous water wash equipment, modifying the C-304 exchanger piping to be symmetrical and allow equivalent water wash injection to both bays, modifying the compressor to accommodate higher hydrogen purity, and modifying the stripper for new feed tray location and flooding in the top of the tower. There will be increases in fugitive component counts as a result of the modifications to the DDU. No modifications are being made to the furnaces at the DDU.

2.3.9 VAPOR RECOVERY UNIT (VRU) 300

The VRU 300 (Section D.6 of the Title V permit) will need to process a larger amount of lighter naphtha feed with the CXHO project, given that the heavy Canadian crude must be diluted with light naphtha prior to introducing it into the project pipeline that will transport it to BP Whiting. Several modifications are required on the unit, which include replacing trays in the T-303 distillation tower, replacing and/or modifying various pumps and replacing some reboilers and coolers. In addition the T-370 and T-380 debutanizers will have modifications to the tower internals, reboilers and the addition of a second product booster pump.

Due to the addition of the vapor recovery at the new Coker, the 350 section of the unit will be shut down. Additionally, some of the sewers associated with VRU 300 will be shut down and sealed.

2.3.10 FUEL GAS SYSTEM

As part of the CXHO project, BP Whiting will be making enhancements to the refinery's fuel gas system to achieve a future potential total reduced sulfur (TRS) content of 80 parts per million

(ppmv) or less in the refinery fuel gas, which is used as a fuel source for the new and existing process heaters.

2.3.11 FUGITIVE COMPONENTS

Modifications to existing fugitive components will be made as part of the CXHO project. These modifications include the shutdown of existing components. In addition, new fugitive components will be installed as part of the project. These components include flanges, valves, pumps, and compressors related to process equipment and product and intermediate storage and piping. All associated fugitive emission changes as a result of the CXHO project are estimated as discussed in Section 3.2.6.

2.3.12 BLENDING OIL UNIT

Modifications will be made to the Blending Oil Unit (BOU) heater F-401 (Section D.11 of the Title V Permit). The burners will be replaced and the furnace floor will be moved closer to grade as part of the CXHO Project to enable the necessary fuel usage, however the permitted capacity of this unit will not be increased.

2.3.13 PROPYLENE CONCENTRATION UNIT

With the CXHO project, the refinery will produce more RGP (refinery grade propylene) and will minimize the production of PGP (polymer grade propylene). This will require the addition of a dryer for removal of moisture from the RGP which contains more water, some heat exchanger modifications and some piping and pump replacements at the Propylene Concentration Unit (Section D.8 of the Title V Permit).

2.3.14 BUTANE, PROPANE & PROPYLENE STORAGE & LOADING FACILITIES

There will be no increase in emissions from the Butane, Propane & Propylene storage and loading facilities (Section D.14 of the Title V Permit) to the PIB flare associated with the CXHO Project. A recovery device will be installed (i.e. chiller) to reduce and/or eliminate emissions to the flare. This modification would solely be an emission reduction project. No emission credits for this project have been included with this application.

2.3.15 TEMPORARY CONCRETE CRUSHER

As part of the site preparation and demolition activities for the CXHO project, a contractor will bring a concrete crusher on site to crush concrete to a size that can be used for backfill. The crusher will be used as necessary to crush approximately 9,000 cubic yards of concrete. Front end loaders and trucks will be used to transfer the backfill material.

The concrete crusher will be a mobile unit that is self-propelled; therefore, it will be a nonroad engine per section (1)(i) of the definition of "nonroad engine" in 40 CFR 1068.30. Since these criteria are met, the diesel engine is a non-road engine, the pump is not part of a "stationary source" per 326 IAC 1-2-73. The engine portion of the unit will not be considered an "emissions unit" per 326 IAC 1-2-23.5 since it is not part of a "stationary source". Therefore, no permitting will be required for the engine.

2.4 AFFECTED UNITS

There are many other existing units at the refinery that are not being physically modified as part of the CXHO project, but they are impacted by the project, due to the change in crude slate. These units are considered “affected” units and include the following:

- 11A PS (Section D.1 of the Title V permit),
- CFHU (Section D.19 of the Title V permit),
- CRU (Section D.20 of the Title V permit),
- FCU500 (Section D.21 of the Title V permit),
- VRU 100/200 (Section D.5 of the Title V permit), and
- PCU (Section D.8 of the Title V permit).

The emissions from these units were evaluated by a similar process as for the modified units. Further details of this evaluation are included in Section 3.4 and in Appendix C.

As noted in Section 2.1, some portions of the refinery (e.g., loading operations, storage tanks, asphalt production, steam boilers, etc.) will be unaffected by the CXHO project.

2.5 SHUTDOWN UNITS

BP Whiting will be permanently shutting down and removing from service a number of units as a result of the installation of new units and the modification of certain existing units comprising the CXHO project. The following existing units will be permanently shut down as part of the CXHO project:

- No. 11B Coker Heaters H-101, 102, 103, and 104 (Section D.2 of the Title V permit),
- Existing Coke Handling System (Section D.2 of the Title V permit),
- Beavon-Stretford Tail Gas Unit (Section D.4 of the Title V permit),
- SBS Tail Gas Unit (Section D.4 of the Title V permit),
- SBS Cooling Tower (Section D.4 of the Title V permit),
- SRU Incinerator (Section D.4 of the Title V permit)²,
- No. 12 PS Heaters H-2, H-1AS/1AN, H-1CN, H-1B, H-1CX (Section D.3 of the Title V permit),
- No. 4C Treating Plant (Section D.13 of the Title V permit),
- No. 3 Ultraformer (Section D.15 of the Title V permit),
- The 350 section of VRU 300 (Section D.6 of the Title V permit)
- No. 1 SPS Boilers (Section D.23 of the Title V permit)

Note that BP previously identified two asphalt storage tanks that were anticipated to be shutdown as part of the asphalt project (i.e., tanks TK-6126 and TK-6127). These tanks will not be shutdown as previously anticipated, however BP did not identify any emissions credit for the shutdown of these tanks, therefore, this change has no impact on project emissions.

² Note that BP is conservatively basing the emissions reduction from the shutdown of the SRU Incinerator only on the normal operation emissions during the baseline (i.e., natural gas pilot combustion).

3. NETTING ANALYSIS AND EMISSION CALCULATIONS

The following section details the methodology and calculations used in determining the emission changes that will result from the CXHO project. Because of the large number of emission units involved, only the formulas and data sources are described here along with example calculations. The results of applying the formulas to each of the new, modified and affected emission units are documented and presented in full detail in Appendix C.

3.1 METHODOLOGY

The overall objective of the emission calculations presented in this section is to determine which, if any, of the major NSR requirements apply to the project.³ The Whiting Refinery is located in Lake County, which is designated as an attainment area for PM₁₀, nitrogen dioxide (NO₂), SO₂, CO, and lead (Pb). As a result, federal PSD requirements would be applicable if the CXHO project resulted in a significant net emission increase for any of these pollutants. In addition, Lake County is designated non-attainment for ozone and PM_{2.5}. As a result, federal non-attainment NSR would be applicable if there were a significant net emission increase in ozone precursors (VOC or NO_x) or PM_{2.5}.

It should be noted that Indiana's Major NSR (PSD and Non-attainment NSR) provisions regulate emissions of following forms of particulate matter:

- (i) Particulate Matter (PM Filterable) (considered a regulated NSR pollutant because it is regulated under Section 111 of the CAA);
- (ii) Particulate Matter with diameter less than 10 microns (PM₁₀ Filterable and Condensable) (considered a regulated NSR pollutant because U.S. EPA has promulgated a NAAQS for PM₁₀); and
- (iii) Particulate Matter with diameter less than 2.5 microns (PM_{2.5} Filterable and Condensable) (considered a regulated NSR pollutant because U.S. EPA has promulgated a NAAQS for PM_{2.5}).

Therefore, this application includes separate baseline actual emissions and post project potential emissions for three forms of particulate matter regulated under the Major NSR programs. No analysis was performed for Total Suspended Particulate (TSP) since, both state and federal Major NSR requirements do not regulate TSP emissions. However, the net emissions change for TSP is expected to be similar to that for PM for the proposed project.

While the substantive requirements that apply under PSD and non-attainment NSR differ, the process for determining whether there has been a significant net emission increase is the same for both programs. The major steps involved in this process are outlined per 326 IAC 2-2-2 (d) as follows:

The requirements of this rule will be applied in accordance with the following:

³ The Whiting Refinery operations are classified under Standard Industrial Classification (SIC) Code 2911. Operations classified under this SIC group are considered petroleum refineries and are one of the 28 listed source categories under 326 IAC 2-2-1(gg); therefore, the Whiting Refinery is subject to the 100 tpy threshold instead of the 250 tpy threshold for a major stationary source.

(1) Except as otherwise provided in subsections (e) and (f), and consistent with the definition of major modification contained in section 1(ee) of this rule, a project is a major modification for a regulated NSR pollutant if it causes both a significant emissions increase and a significant net emissions increase. The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

The major steps involved in this process are as follows:

Step 1: For each new emission unit, the annual potential emissions were calculated as required. Baseline emissions for all new emission units were conservatively assumed to be zero even where the new emission units replaced existing emission units that served the same function.

Step 2: The impact of the CXHO project on each existing emission unit modified or affected by the CXHO project was calculated by comparing future potential emissions for that unit to baseline actual annual emissions for that unit, as required by 326 IAC 2-2-2(d)(4). This approach is more conservative than another approach allowed under the major new source review requirements per 326 IAC 2-2-2(d)(6) which allows the use of future projected actual emissions instead of potential emissions for existing units. In addition, BP has conservatively calculated the increase in emissions that result from the project without using additional provisions allowed under the major new source review. These requirements allow the exclusion of the portion of future projected actual emissions that could have been accommodated in the baseline period and that are unrelated to the project, including any increased utilization due to product demand growth.

Step 3: The emission increases resulting from steps 1 and 2 were then summed to determine if the project resulted in a significant emissions increase (i.e. the first step described in 326 IAC 2-2-2(d)(1) above).

Step 4: Since Step 3 resulted in a significant emissions increase, the emissions decreases resulting from the CXHO project (calculated in Step 2 above) and other contemporaneous emission increases and decreases were considered to determine if the project would result in a significant *net* emissions increase.

The formulas and data sources used in these calculations are provided in the following subsections. The results of these calculations as applied to all new, modified and affected emission units are documented and presented in Appendix C. As demonstrated by these calculations, the CXHO project will not result in a significant net emission increase for any pollutant. Thus, neither federal nonattainment major NSR nor federal PSD requirements apply for any pollutant.

3.2 NEW UNITS

As part of the CXHO project BP proposes to construct new units as identified in Section 2.2 of this application. Emissions calculations for these various types of units are discussed in the following sections.

3.2.1 PROCESS HEATERS

BP Whiting plans to construct a new DHT heater (B-601A), GOHT heaters (F-901A and F-901B), three new 12 PS heaters (H-101A, H-101B and H-102), and three new coker heaters (H-201, H-202, and H-203). These new heaters will have the capability to fire refinery gas and natural gas. BP Whiting is also including the emissions from the two new heaters for the new hydrogen unit (HU-1 and HU-2) even though BP may subsequently arrange to have the new hydrogen unit constructed and operated by a third party. The hydrogen unit heaters will have the capability to fire natural gas and pressure swing adsorption (PSA) offgas.

Since the only emissions from these new process heaters are the result of the combustion of natural gas, refinery gas, and/or PSA offgas, emissions are a function of the heat input capacities of the heaters.

The proposed maximum heat input capacities for these heaters are detailed in Table 3.1.

TABLE 3.1 NEW PROCESS HEATERS MAXIMUM HEAT INPUT CAPACITIES

Unit	Maximum Heat Input Capacity (MMBtu/hr)
DHT	
B-601A	41.9
GOHT	
F-901A	47
F-901B	47
12 PS	
H-101A	355
H-101B	355
H-102	331
Coker	
H-201	208
H-202	208
H-203	208
Hydrogen Plant	
HU-1	920
HU-2	920

3.2.1.1 VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

The combustion annual VOC emissions for all new process heaters are calculated using emission factors from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) as is presented in Equation 3-1.⁴

⁴ Process heaters at the BP Whiting refinery fire mainly refinery fuel gas. Refinery fuel gas is very similar in composition to natural gas, with the possible exception of its sulfur content. AP-42 emission factors for natural gas combustion

Equation 3-1

$$Emissions(tpy) = D * VOC\ EF_{AP-42} * \frac{1}{HHV_{AP-42}} * 8,760 \frac{hr}{yr} * \frac{1\ ton}{2,000\ lb}$$

Where,

D = Maximum Heat Input Capacity (MMBtu/hr)

VOC EF_{AP-42} = AP-42 emission factor (lb/MMscf)

HHV_{AP-42} = natural gas higher heating value assumed by AP-42 (MMBtu/MMscf)

For example, the VOC emissions from the GOHT heater F-901A are:

$$VOC\ (tpy) = 47 \frac{MMBtu}{hr} * 5.5 \frac{lb}{MMscf} * \frac{1}{1,020} \frac{MMscf}{MMBtu} * 8,760 \frac{hr}{yr} * \frac{1\ ton}{2,000\ lb}$$

$$VOC\ (tpy) = 1.1\ tpy$$

A complete list of emission factors can be located in Appendix C (Tables C.1 to C.10), and VOC emissions associated with new units can be located in Appendix C (Tables C.11 and C.81).

3.2.1.2 NITROGEN OXIDE (NO_x) AND CARBON MONOXIDE (CO) EMISSIONS

The NO_x and CO emissions for all new process heaters are based on vendor guarantee emission rates and are detailed in Table 3.2.

are a good representation of refinery fuel gas combustion emissions for all criteria pollutants except SO₂ and it is common practice in the refining industry to utilize these factors. PSA offgas is conservatively presumed to have similar emissions characteristics as natural gas, with the exception of SO₂ emissions.

TABLE 3.2 NO_x AND CO EMISSION RATES

Unit	NO _x Emission Rate (lb/MMBtu)	NO _x Control	CO Emission Rate (lb/MMBtu)	CO Control
DHT				
B-601A	0.04	Ultra-Low NO _x Burners	0.04	good combustion practices
GOHT				
F-901A	0.04	Ultra-Low NO _x Burners	0.02	good combustion practices
F-901B	0.04	Ultra-Low NO _x Burners	0.02	good combustion practices
12 PS				
H-101A	0.05	Ultra-Low NO _x Burners	0.019	good combustion practices
H-101B	0.05	Ultra-Low NO _x Burners	0.019	good combustion practices
H-102	0.05	Ultra-Low NO _x Burners	0.019	good combustion practices
Coker				
H-201	0.02	Low NO _x Burners and SCR	0.019	good combustion practices
H-202	0.02	Low NO _x Burners and SCR	0.019	good combustion practices
H-203	0.02	Low NO _x Burners and SCR	0.019	good combustion practices
Hydrogen Plant				
HU-1	0.013	Low NO _x Burners and SCR	0.015	good combustion practices
HU-2	0.013	Low NO _x Burners and SCR	0.015	good combustion practices

The methodology to calculate NO_x and CO emissions is presented in Equation 3-2.

Equation 3-2

$$NO_x \text{ Emissions}(tpy) = D * NO_x \text{ EF} * 8,760 \frac{hr}{yr} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

Where,

D = Maximum Heat Input Capacity (MMBtu/hr)

NO_x EF = NO_x emission factor (lb/MMBtu)

For example, the NO_x emissions from the GOHT heater F-901A are:

$$NO_x (tpy) = 47 \frac{MMBtu}{hr} * 0.04 \frac{lb}{MMBtu} * 8,760 \frac{hr}{yr} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$NO_x (tpy) = 8.2 \text{ tpy}$$

A complete list of emission factors can be located in Appendix C (Tables C.1 to C.10), and NO_x and CO emissions associated with new units can be located in Appendix C (Tables C.11 and C.81).

3.2.1.3 SULFUR DIOXIDE (SO₂) EMISSIONS

SO₂ emissions from the process heaters can be calculated using Equation 3-3.

Equation 3-3

$$SO_2 \text{ Emissions} = D * SO_2 \text{ EF} * \frac{1}{HHV_F} 8,760 \frac{hr}{yr} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

Where,

D = Maximum Heat Input Capacity (MMBtu/hr)

HHV_F = Fuel gas higher heating value (MMBtu/MMscf)

SO₂ EF = SO₂ emission factor (lb/MMscf)

The emission factor (SO₂ EF) in the above equation is a function of the total sulfur concentration in the fuel gas and can be calculated from the Ideal Gas Law as follows:

Equation 3-4

$$SO_2 \text{ EF} = \frac{C * MW * P}{R * T}$$

Where,

C = Fuel gas total sulfur concentration (ppmv)

MW = Molecular Weight (lb/lbmol)

P = Pressure (psia)

R = Ideal Gas Constant (psia*ft³/(lbmol*R))

T = Temperature (R)

Regarding the CXHO project, the TRS in fuel gas will be limited to 80 ppmv. This level of TRS is accomplished primarily by building a new VRU for the new Coker process unit. The new VRU is specifically designed to limit the amount of mercaptans in the fuel gas to less than 20 ppmv by reducing propane (and thus mercaptans) in the fuel gas. The H₂S content of the fuel gas will continue to be about 40 ppmv by scrubbing the fuel gas with additional amine contactor capacity.

It is assumed that 1 mole of sulfur compounds in the fuel gas will yield 1 mole of SO₂ emissions. Therefore, the SO₂ emission factor can be calculated in accordance with Equation 3-4:

$$SO_2 \text{ EF} = (80 \text{ ppm}) * \left(\frac{1 \text{ lbmol } SO_2}{1 \text{ lbmol total sulfur}} \right) * \left(\frac{64.06 \text{ lb } SO_2}{1 \text{ lbmol } SO_2} \right) * \frac{14.7 \text{ psi}}{\left(10.73 \frac{\text{psi} \cdot \text{ft}^3}{\text{lbmol} \cdot \text{R}} \right) * (67.7 + 460)^\circ \text{R}}$$

$$SO_2 \text{ EF} = 13.30 \frac{\text{lb } SO_2}{\text{MMscf}}$$

The projected future actual annual average fuel gas higher heating value is 1203.3 MMBtu/MMscf.

Therefore, the annual SO₂ emissions from the new coker heater H-201 calculated using Equation 3-3 are, for example:

$$SO_2 \text{ (tpy)} = 208 \frac{\text{MMBtu}}{\text{hr}} * 13.30 \frac{\text{lb}}{\text{MMscf}} * \frac{1}{1,203.3} \frac{\text{MMscf}}{\text{MMBtu}} * 8,760 \frac{\text{hr}}{\text{yr}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$SO_2 \text{ (tpy)} = 10.1 \text{ tpy}$$

Note that, for purpose of estimating SO₂ emissions, BP is assuming that all sulfur oxides are emitted in the form of SO₂.⁵ This assumption is conservative, since, as discussed below, as much as 3% of the total sulfur oxides emitted will be in the form of SO₃, which will be emitted as either condensable PM₁₀/PM_{2.5} or sulfuric acid mist.

The new hydrogen unit heaters HU-1 and HU-2 will combust both natural gas and PSA offgas with a fuel ratio of no more than 25% natural gas and the remainder PSA offgas. As there is no sulfur in the PSA gas, the sulfur percentage of the fuel combusted will be determined by the maximum percentage of natural gas fired. Therefore, the SO₂ emissions from the new hydrogen unit heater HU-1 can be calculated as:

$$SO_2 \text{ (tpy)} = 920 \frac{\text{MMBtu}}{\text{hr}} * 25\% * 0.6 \frac{\text{lb}}{\text{MMscf}} * \frac{1}{1,020} \frac{\text{MMscf}}{\text{MMBtu}} * 8,760 \frac{\text{hr}}{\text{yr}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$SO_2 \text{ (tpy)} = 0.6 \text{ tpy}$$

SO₂ emissions associated with new units can be located in Appendix C (Tables C.11 and C.81).

3.2.1.4 PARTICULATE MATTER (PM/PM₁₀/PM_{2.5}) EMISSIONS

The combustion-related PM emissions for all new process heaters are calculated using the filterable PM emission factor from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) in Equation 3-1, above.

For example, the annual PM emissions from the new coker heater H-201 are:

$$PM = 208 \frac{\text{MMBtu}}{\text{hr}} * 1.9 \frac{\text{lb}}{\text{MMscf}} * \frac{1}{1,020} \frac{\text{scf}}{\text{Btu}} * 8,760 \frac{\text{hr}}{\text{yr}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

⁵ Sulfur contained in fuel is emitted in the form of oxides of sulfur (SO_x) via combustion. The vast majority of sulfur contained in refinery fuel gas will be emitted in the form of SO₂ combustion emissions, however, a small fraction of the fuel sulfur may be emitted in the form of other sulfur oxides (i.e., SO₃). In order to conservatively estimate emissions, BP Whiting is "double counting" some fraction of sulfur oxides by assuming that all sulfur is emitted in the form of SO₂ for SO₂ emission calculations.

$$PM = 2.3 \text{ tpy}$$

The combustion-related PM₁₀/PM_{2.5} emissions for all new process heaters are calculated using the total PM emission factor from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) in Equation 3-1, above.

For example, the annual PM₁₀/PM_{2.5} emissions from the new coker heater H-201 are:

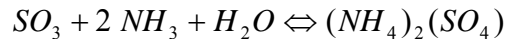
$$PM_{10} / PM_{2.5} = 208 \frac{MMBtu}{hr} * 7.6 \frac{lb}{MMscf} * \frac{1}{1,020} \frac{scf}{Btu} * 8,760 \frac{hr}{yr} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$PM_{10} / PM_{2.5} = 6.8 \text{ tpy}$$

It should be noted that calculated emissions resulting from use of this methodology are below the Lake County PM₁₀ SIP Limit of 0.03 grains per dry standard cubic foot (gr/dscf).

Additional particulate matter emissions will be generated at the new coker and hydrogen plant as a result of the SCRs, which chemically reduce NO_x emissions through a reaction with ammonia (NH₃). This process can produce additional particulate emissions through the production of ammonium sulfate ((NH₄)₂(SO₄)). The additional PM₁₀/PM_{2.5} emissions from the heaters with SCRs are conservatively calculated by assuming 3% of the SO_x emitted by the heater is in the form of SO₃, and that all of this SO₃ reacts to form (NH₄)₂(SO₄) as shown in Equation 3-5. This is a conservative assumption since, as discussed below, some fraction of the SO₃ emitted will react to form sulfuric acid mist.⁶

Equation 3-5



The additional PM₁₀/PM_{2.5} emissions from the condensable (NH₄)₂(SO₄) can be calculated using the methodology in Equation 3-6 for the heaters with SCRs.

Equation 3-6

PM (in the form of (NH₄)₂(SO₄)) [lb] =

$$lb \text{ SO}_2 \text{ emitted} * \frac{1 \text{ mol SO}_2}{64.06 \text{ lb SO}_2} * \frac{3\% \text{ mol SO}_3}{100 \text{ mol SO}_2} * \frac{1 \text{ mol (NH}_4)_2(\text{SO}_4)}{1 \text{ mol SO}_3} * \frac{132.12 \text{ lb (NH}_4)_2(\text{SO}_4)}{1 \text{ mol (NH}_4)_2(\text{SO}_4)}$$

⁶ Sulfur contained in fuel is emitted in the form of oxides of sulfur (SO_x) via combustion. The vast majority of sulfur contained in refinery fuel gas will be emitted in the form of SO₂ combustion emissions, however, a small fraction of the fuel sulfur may be emitted in the form of other sulfur oxides (i.e., SO₃). In order to conservatively estimate emissions, BP Whiting is "double counting" some fraction of sulfur oxides by assuming that all sulfur is emitted in the form of SO₂ for SO₂ emission calculations.

For example, the annual SO₂ emissions from one of the new coker heaters, H-201, was calculated in Section 3.2.1.3 to be 10.1 tpy. Therefore, the additional PM₁₀/PM_{2.5} emissions from one of the new coker heaters as a result of the SCR reaction are:

$$\begin{aligned}
 PM_{10} / PM_{2.5} \text{ (tpy)} &= 10.1 \frac{\text{ton } SO_2}{\text{yr}} * \frac{2,000 \text{ lb}}{1 \text{ ton}} * \frac{1 \text{ mol } SO_2}{64.06 \text{ lb } SO_2} * \frac{3\% \text{ mol } SO_3}{100 \text{ mol } SO_2} \\
 &* \frac{1 \text{ mol } (NH_4)_2(SO_4)}{1 \text{ mol } SO_3} * \frac{132.12 \text{ lb } (NH_4)_2(SO_4)}{1 \text{ mol } (NH_4)_2(SO_4)} * \frac{1 \text{ ton}}{2,000 \text{ lb}} \\
 PM_{10} / PM_{2.5} &= 0.6 \text{ tpy}
 \end{aligned}$$

Therefore, the total PM₁₀/PM_{2.5} emissions from the new coker heater H-201 are the sum of the combustion emissions and the additional emissions as a result of the SCR reaction.

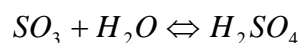
$$\begin{aligned}
 PM_{10} / PM_{2.5} &= 6.8 \text{ tpy} + 0.6 \text{ tpy} \\
 PM_{10} / PM_{2.5} &= 7.4 \text{ tpy}
 \end{aligned}$$

Note that for units not equipped with SCR, the PM₁₀/PM_{2.5} emissions are calculated exclusively from the AP-42 emission factor. Detailed PM₁₀/PM_{2.5} emissions associated with new units can be located in Appendix C (Tables C.11 and C.81).

3.2.1.5 SULFURIC ACID MIST (H₂SO₄ MIST) EMISSIONS

As discussed in Section 3.2.1.4, combustion emissions are assumed to include some amount of SO₃, which can react to form condensable particulate matter in the form of (NH₄)₂(SO₄) if ammonia is present in the fuel gas. However, this SO₃ can also react with water vapor present in the stack to produce sulfuric acid mist (H₂SO₄ mist). Conservatively, BP is considering that all of the SO₃ emitted can form both condensable particulate matter and H₂SO₄ mist. Calculations for H₂SO₄ mist emissions are shown in Equation 3-7.

Equation 3-7



H₂SO₄ mist emissions are conservatively calculated by assuming 3% of the SO_x emitted by the heater are in the form of SO₃, and assuming that all of the SO₃ will react to form H₂SO₄. The amount of H₂SO₄ mist emitted can be calculated using the methodology in Equation 3-8.

Equation 3-8

$$H_2SO_4 = lb\ SO_2\ Emitted * \frac{1\ mol\ SO_2}{64.06\ lb\ SO_2} * \frac{3\%}{100} \frac{mol\ SO_3}{mol\ SO_2} * \frac{1\ mol\ H_2SO_4}{1\ mol\ SO_3} * \frac{98.07\ lb\ H_2SO_4}{1\ mol\ H_2SO_4}$$

$$* 8,760\ \frac{hr}{yr} * \frac{1\ ton}{2,000\ lb}$$

The SO₂ emissions from the new coker heater H-201 were calculated in Section 3.2.1.3 to be 10.1 tpy. The H₂SO₄ emissions from the new coker heater H-201 are calculated to be:

$$H_2SO_4\ (tpy) = 10.1\ \frac{ton\ SO_2}{yr} * \frac{2,000\ lb}{1\ ton} * \frac{1\ mol\ SO_2}{64.06\ lb\ SO_2} * \frac{3\%}{100} \frac{mol\ SO_3}{mol\ SO_2} * \frac{1\ mol\ H_2SO_4}{1\ mol\ SO_3}$$

$$* \frac{98.07\ lb\ H_2SO_4}{1\ mol\ H_2SO_4} * \frac{1\ ton}{2,000\ lb}$$

$$H_2SO_4\ (tpy) = 0.46\ tpy$$

H₂SO₄ mist emissions calculations can be located in Appendix C (Tables C.11 and C.81).

3.2.1.6 LEAD (Pb) EMISSIONS

The combustion Pb emissions for all new process heaters are calculated using emission factors from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) and the calculation methodology outlined in Equation 3-1.

Pb emissions calculations can be located in Appendix C (Tables C.11 and C.81).

3.2.1.7 MERCURY (Hg) EMISSIONS

The combustion mercury emissions for all new process heaters are calculated using emission factors from API / WSPA Emission Factors for Boilers / Heaters using Process Gas (1998 - Table ES-1) and the calculation methodology outlined in Equation 3-1. It should be noted that the future crude slate of the refinery will not have a higher mercury content than that currently processed. The mercury content of various crude oils from around the world that are currently processed at Whiting is consistent with the mercury content of Canadian bitumen which will be processed at Whiting in the future as part of this project. Mercury emissions calculations can be located in Appendix C (Tables C.11 and C.81).

3.2.1.8 BERYLLIUM (Be) EMISSIONS

The combustion beryllium emissions for all new process heaters are calculated using emission factors from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) and the calculation methodology outlined in Equation 3-1. Beryllium emissions calculations can be located in Appendix C (Tables C.11 and C.81).

3.2.2 SULFUR RECOVERY COMPLEX

The sulfur recovery complex will consist of two new Claus sulfur recovery trains (D & E), two new amine units (C & D), and two new sour water strippers to supplement the existing three Claus trains (A, B & C), two amine units (A & B), and the sour water stripper. The existing Beavon-Stretford TGU and SBS TGU will be shutdown and replaced with two new COTs. The new Claus trains are designed with oxygen enrichment, which will enable them to operate at a higher process rate if needed due to shutdown of the other trains. The annual average capacity for the total sulfur recovery complex will be 1,300 long tons per day (LTPD).

The new Claus trains, amine units, and sour water strippers do not have any direct vents to the atmosphere and therefore have no direct emissions. Emissions from the sulfur storage pits will be routed back to the Claus trains; therefore, there will be no emissions from the sulfur pits. The two new Claus sulfur recovery trains along with the existing three Claus sulfur recovery trains will be vented through one or both of the two new COTs. Under normal operating conditions, each COT will be able to operate such that the two units combine to handle the total Claus outlet loads; however, the COTs have been designed to provide 100% redundancy in the event that one of the units needs to be brought offline. The two existing TGUs (Beavon Stretford & SBS) will be shutdown.

The COT thermal oxidizers combust natural gas and are rated at 72 MMBtu/hr for each COT. Therefore, the total natural gas usage for two COT thermal oxidizers is 144 MMBtu/hr. The VOC, NO_x, SO₂, PM/PM₁₀/PM_{2.5}, CO, and Lead emissions attributable combustion were calculated using emission factors from EPA's AP-42 tables for natural gas combustion Section 1.4 (July 1998) and the calculation methodology is presented in Equation 3-1.

The COT combustion emissions are located in Appendix C (Table C.19).

The SO₂ process emissions from the COTs were calculated using the design airflow and SO₂ outlet concentration as detailed in Equation 3-9.

Equation 3-9

$$\text{COT Process SO}_2 \text{ Emissions} = \text{Airflow} * \frac{C}{10^6} * \frac{MW \text{ SO}_2}{MW \text{ Air}}$$

Where,

Airflow = The design airflow at standard conditions (ft³/hr)

C = SO₂ Concentration (ppmv)

MW SO₂ = Molecular Weight of SO₂ (lb/lbmol)

MW Air = Molecular Weight of Air at standard conditions (lb/lbmol)

Note that standard conditions were assumed to be 1 atm of pressure at 68 °F; therefore, the molecular weight of air is assumed to be 385 lb air/lbmol. The design airflow rate and SO₂ outlet

concentration for the sulfur recovery complex operating at 1,300 LTPD is 5,929,500 scfh and 45 ppmv, respectively. Therefore, the SO₂ process emissions are calculated as:

$$\text{COT Process SO}_2 \text{ Emissions} = 5,929,500 \text{ scfh} * \frac{45 \text{ ppm}}{10^6} * \frac{64.06 \text{ lb SO}_2 / \text{lbmol}}{385 \text{ lb air} / \text{lbmol}} * \frac{8,760 \text{ hr}}{1 \text{ yr}} * \frac{1 \text{ lb}}{2,000 \text{ ton}}$$

$$\text{COT Process SO}_2 \text{ Emissions} = 194.46 \text{ tpy}$$

In addition to the combustion emissions, there are some CO and H₂S emissions inherent to the sulfur recovery process. These additional CO emissions are anticipated to be 23.5 ton/yr and 8.9 tpy, respectively. The COT process emissions are located in Appendix C (Table C.19).

Note that there are also emissions of H₂S resulting from the loading of sulfur product. These are detailed in Table C.19 and are based on the H₂S content of the sulfur as it is loaded.

3.2.3 COOLING TOWERS

As part of the CXHO project, three new cooling towers will be constructed. Emissions from these cooling towers are a function of the rate at which water circulates in the towers. The annual average recirculation rates for these new cooling towers are detailed in Table 3.3.

TABLE 3.3 NEW COOLING TOWER RATES

Unit	Recirculation Rates (gallons per minute [gpm])
Cooling Tower 7	21,000
Cooling Tower 8	90,000
HU Cooling Tower	14,000

3.2.3.1 VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

The new cooling tower VOC emissions were calculated using emission factors from EPA's AP-42 Tables for fugitive emissions from petroleum refining Section 5.1 (January 1995). The calculation methodology is presented in Equation 3-10.

Equation 3-10

$$\text{VOC Emissions} = (R + M) * EF_{AP-42}$$

Where,

R = Recirculation Rate (gpm)

M = Make-up rate (gpm)

The make-up rate for the new cooling towers was calculated as a ratio from the average make-up rate for the existing six cooling towers at the refinery using Equation 3-11.

Equation 3-11

$$\text{Make-Up Rate} = M_{AVG} * \frac{R_N}{R_{AVG}}$$

Where,

M_{AVG} = Average make-up rate for existing cooling towers 1 through 6 (gpm)

R_N = Recirculation rate for new cooling tower (gpm)

R_{AVG} = Average recirculation rate for existing cooling towers 1 through 6 (gpm)

For example, the average recirculation and make-up rates for the existing cooling towers are 44,750 and 961 gpm, respectively. Therefore, the make-up rate for the new Cooling Tower 7 is:

$$\text{Make-Up Rate} = 961 \text{ gpm} * \frac{21,000 \text{ gpm}}{44,750 \text{ gpm}}$$

$$\text{Make-Up Rate} = 451 \text{ gpm}$$

Therefore, the annual VOC emissions from cooling tower 7 are:

$$\text{VOC (tpy)} = \left(21,000 \frac{\text{gal}}{\text{min}} + 451 \frac{\text{gal}}{\text{min}} \right) * 0.7 \frac{\text{lb}}{\text{MMgal}} * \frac{1 \text{ MMgal}}{10^6 \text{ gal}} * \frac{60 \text{ min}}{1 \text{ hr}} * \frac{8,760 \text{ hr}}{1 \text{ yr}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$\text{VOC (tpy)} = 3.9 \text{ tpy}$$

The VOC emissions from the new cooling towers can be located in Appendix C (Tables C.26 and C.81). Note that the HU Cooling Tower is not in service in petroleum refinery operations, therefore, there are no VOC emissions estimated from this cooling tower.

3.2.3.2 PARTICULATE MATTER (PM/PM₁₀/PM_{2.5}) EMISSIONS

The PM/PM₁₀/PM_{2.5} emissions from the new cooling towers are calculated using emission factors from EPA's AP-42 Tables for wet cooling towers Section 13.4 (January 1995). The AP-42 PM₁₀ emission rate is calculated based on a given total liquid drift and total dissolved solid (TDS) content. The future cooling tower emissions were calculated by a ratio of the AP-42 emission factor to the design total liquid drift and TDS content as demonstrated in Equation 3-12.

Equation 3-12

$$PM / PM_{10} / PM_{2.5} \text{ EF} = PM \text{ EF}_{AP-42} * \frac{TLD_{design}}{TLD_{AP-42}} * \frac{TDS_{future}}{TDS_{AP-42}}$$

Where,

$PM \text{ EF}_{AP-42}$ = AP-42 Emission Factor for PM₁₀ (lb/1000 gal)

TLD_{design} = Design total liquid drift (%)

TLD_{AP-42} = Design total liquid drift (%)

TDS_{future} = Estimated future total dissolved solid content (mg/L)

TDS_{AP-42} = Total dissolved solid content used in AP-42 (mg/L)

The new cooling towers will be equipped with high efficiency drift eliminators that provide PM/PM₁₀/PM_{2.5} control by reducing the total liquid drift to 0.001%. The future annual average TDS is estimated to be 1,163 mg/L, which is equal to the average TDS for the existing cooling towers 1 through 6. The total liquid drift and TDS specified in the AP-42 emission factor calculation are 0.02% and 12,000 ppm (mg/L), respectively. Therefore, the PM/PM₁₀/PM_{2.5} emission factor for the new cooling towers is:

$$PM / PM_{10} / PM_{2.5} EF = 0.019 \frac{lb}{1,000 gal} * \frac{0.001\%}{0.02\%} * \frac{1,163 \frac{mg}{L}}{12,000 \frac{mg}{L}}$$

$$PM / PM_{10} / PM_{2.5} EF = 9.2e-5 \frac{lb}{1,000 gal}$$

The PM/PM₁₀/PM_{2.5} emissions can therefore be calculated using the methodology detailed in Equation 3-13.

Equation 3-13

$$PM / PM_{10} / PM_{2.5} = (R + M) * PM EF$$

Where,

R = Recirculation rate (1,000 gal/min)

M = Make-up rate (1,000 gal/min)

For Example, the annual PM/PM₁₀/PM_{2.5} emissions for cooling tower 7 are:

$$PM = \left(21,000 \frac{gal}{min} + 451 \frac{gal}{min} \right) * \frac{1}{1,000} \frac{1,000 gal}{gal} * 9.2e-5 \frac{lb}{1,000 gal} * \frac{60 min}{1 hr} * \frac{8,760 hr}{1 yr} * \frac{1 ton}{2,000 lb}$$

$$PM / PM_{10} / PM_{2.5} = 0.5 tpy$$

The PM/PM₁₀/PM_{2.5} emissions from the new cooling towers are located in Appendix C (Tables C.26 and C.81).

3.2.4 COKE HANDLING AND STORAGE

Coke handling operations will be expected to operate under the main operating scenario for 95% of operating hours annually. There will also be an alternative operating scenario which will consist of three enclosed conveyors with unenclosed transfer points. This operating scenario exists as a contingency for malfunctions that could occur within the enclosed coke handling system. Coke handling operations are expected to operate under this emergency operating scenario for no more than 5% of operating hours annually. These scenarios are detailed in the simplified process flow diagram included in Appendix A as Figures A-3a and A-3b. When the

coking process is complete, coke is removed from the coke drums with a high pressure water spray and falls into a pit. The process is cycled between the six coke drums and coke is removed from two drums each cycle. The estimated production of the new coker is 6,000 tons/day of coke. The water saturated coke is moved from the pit to a temporary storage pile to dewater before it is moved by a bridge crane to a partially enclosed coke crusher. From the crusher the coke is conveyed in an enclosed conveyor to a transfer tower. The coke is then transferred using a series of enclosed conveyors to either the enclosed coke storage pile, or to the day bin for loadout into rail cars. Coke is also transferred from the enclosed storage pile using a series of enclosed conveyors back to the transfer tower, for transfer to the day bin for loadout into rail cars. From the day bin, coke will be loaded into rail cars using a telescopic chute to minimize particulate emissions. Particulate emissions from the storage and handling of the coke occur at various transfer points associated with the crusher, covered conveyors, day bin, and load out into the rail cars.

3.2.4.1 MATERIAL HANDLING EMISSIONS

Fugitive emissions from material handling were calculated using EPA's published emission factor from Section 13.2.4 (January 1995), which uses an empirical formula as shown in Equation 3-14.

Equation 3-14

$$EF = k * 0.0032 * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where,

EF = Fugitive emission factor (lb PM/ton of coke handled)

k = Constant that is dependant on particle size, defined in AP-42

U = Mean wind speed (mph)

M = Material moisture content (%)

For example, the emission factor for PM (< 30 µm), has a k equal to 0.74. As documented in Appendix C, the mean wind speed for Chicago, IL as provided in U.S. EPA TANKS 4.0.9d is 10.4 mph. Material moisture content for all transfer points is assumed to be constant at 8%. Thus the PM emission factor for the coke handling transfer points can be calculated as follows:

$$EF_{PM} = 0.74 * 0.0032 * \frac{\left(\frac{10.4}{5}\right)^{1.3}}{\left(\frac{8}{2}\right)^{1.4}}$$

The particulate emissions from material handling for each transfer point are calculated using the methodology in Equation 3-15.

Equation 3-15

$$PM \text{ Emissions} = MH * EF * (1 - CE)$$

Where,

MH = Amount of material handled (ton/yr)

PM EF = PM emission factor (lb PM/ton coke)

CE = Control efficiency (where applicable)

For example, there are ten possible transfer points in the coke handling process, which include transfer from the coke pit crusher to an enclosed conveyor (transfer point 1), multiple enclosed transfer points between enclosed conveyors (transfer points 2, 3, 6, 7 and 8), transfer points to and from the enclosed storage pile (transfer points 4 and 5), the drop into the day bin (transfer point 9), and the load out from the day bin into the rail car (transfer point 10). A control efficiency of 90% is used for transfer points 2 through 9, since the transfer points are enclosed and equipped with water spray controls. A control efficiency of 70% is used for transfer points 1 and 10, since the transfer points will be partially enclosed and equipped with water spray controls. For example, PM emissions from the material handling of coke for the second transfer point are:

$$PM \text{ (tpy)} = 6,000 \frac{\text{ton coke}}{\text{day}} * 365 \frac{\text{day}}{\text{yr}} * 0.74 * 0.0032 * \frac{\left(\frac{10.4}{5}\right)^{1.3}}{\left(\frac{8}{2}\right)^{1.4}} * (1 - 0.90) * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$PM \text{ (tpy)} = 0.09 \text{ tpy}$$

The PM/PM₁₀/PM_{2.5} emissions from the new material handling and storage are located in Appendix C (Tables C.32 and C.33).

3.2.5 FLARES

Three new flare stacks (GOHT Flare, South Flare, and HU Flare) will be constructed as part of the CXHO project to primarily support the new units for the project. Flare gases will be recovered from the new GOHT and South flares by a flare gas recovery system. The recovered gas streams will be sent to a vapor recovery/treating area for removal of H₂S and heavy components before being utilized in the refinery fuel gas system. As such, emissions from these new flares under normal operation will consist only of the emissions from the combustion of natural gas in the flare pilot flames and a small amount of purge gas that is circulated through the flare system for safety reasons (i.e., to prevent air from entering the flare lines). The CXHO project will improve overall reliability at the refinery and is anticipated to reduce emissions from

startup, shutdown, and malfunction events. Therefore, the emissions from startup, shutdown, and malfunction events are not included in the net emissions for the CXHO project.

The HU flare will be operated with a water seal or nitrogen purge. As such there will be no purge gas emissions from the HU flare.

Emissions due to pilot and purge gas combustion from the flares under normal operating conditions have been quantified. The purge and pilot gas flow rates for the new flares are detailed in Table 3.4.

TABLE 3.4 NEW FLARE PURGE AND PILOT GAS FLOW RATES

Unit	Purge Rate (scf/hr)	Pilot Rate (scf/hr)
GOHT Flare	1,800	420
South Flare	3,300	420
HU Flare	N/A	255

3.2.5.1 PILOT EMISSIONS

Since the pilots for the new flares combust natural gas, the VOC, SO₂, CO, PM/PM₁₀/PM_{2.5}, NO_x, and Pb emissions are calculated using EPA published emission factors in AP-42 for natural gas combustion Section 1.4 (July 1998). Equation 3-16 details the methodology to calculate these emissions.

Equation 3-16

$$Emissions = FU_{pilot} * \frac{1 \text{ MMscf}}{10^6 \text{ scf}} * EF_{AP-42}$$

Where,

FU_{pilot} = Flare pilot gas for rate (scf/hr)

EF_{AP-42} = AP-42 Emission Factor (lb/MMscf)

For example, the pilot natural gas usage is estimated to be 420 scf/hr for the GOHT Flare. Therefore, the VOC emissions from the GOHT Flare are:

$$VOC \text{ (tpy)} = 420 \frac{\text{scf}}{\text{hr}} * \frac{1 \text{ MMscf}}{10^6 \text{ scf}} * 5.5 \frac{\text{lb}}{\text{MMscf}} * 8,760 \frac{\text{hr}}{\text{yr}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$VOC \text{ (tpy)} = 0.01 \text{ tpy}$$

The VOC emissions from the new flares are located in Appendix C (Tables C.38 and C.81).

3.2.5.2 PURGE EMISSIONS

3.2.5.2.1 VOLATILE ORGANIC COMPOUND (VOC), CARBON MONOXIDE (CO), AND NITROGEN OXIDE (NO_x) EMISSIONS

The VOC, CO, and NO_x emissions are calculated using EPA published emission factors in AP-42 for industrial flares Section 13.5 (September 1991). Note that unlike the pilot gas, which is natural gas combusted at the flare burner tip, the purge gas (which may be composed of refinery fuel gas) is combusted via the flaring system itself. Therefore, the AP-42 emission factors for industrial flares are more appropriate for estimating emissions from purge gas combustion. Equation 3-17 details the methodology to calculate VOC, CO, and NO_x emissions from flare purge gas combustion.

Equation 3-17

$$Emissions = PH * EF_{AP-42}$$

Where,

PH = Flare purge heat input rate (MMBtu/hr)

EF_{AP-42} = AP-42 emission factor (lb/MMBtu)

The flare purge heat input rate can be calculated using Equation 3-18.

Equation 3-18

$$PH = PR * HHV_F * \frac{1 \text{ MMBtu}}{10^6 \text{ Btu}}$$

Where,

PR = Flare purge rate (scf/hr)

HHV_F = Fuel gas higher heating value (Btu/scf)

For example, the new GOHT flare purge rate is estimated to be 1,800 scf/hr. Therefore, the GOHT flare purge heat input rate is

$$GOHT \text{ PH} = 1,800 \frac{\text{scf}}{\text{hr}} * 1,203.3 \frac{\text{Btu}}{\text{scf}} * \frac{1 \text{ MMBtu}}{10^6 \text{ Btu}}$$

$$GOHT \text{ PH} = 2.17 \text{ MMBtu} / \text{hr}$$

The annual VOC emissions from the GOHT Flare are therefore:

$$VOC \text{ (tpy)} = 2.17 \frac{\text{MMBtu}}{\text{hr}} * 0.14 \frac{\text{lb}}{\text{MMBtu}} * 8.760 \frac{\text{hr}}{\text{yr}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$VOC \text{ (tpy)} = 1.3 \text{ tpy}$$

The VOC emissions from the new flares are located in Appendix C (Tables C.38 and C.81).

3.2.5.2.2 SULFUR DIOXIDE (SO₂) EMISSIONS

The SO₂ emissions from the flare are conservatively estimated using the same methodology used to calculate SO₂ emissions from refinery fuel gas combustion equipment as detailed in Equations 3-3 and 3-4 in Section 3.2.1.3.

The SO₂ emissions estimates from the new flares are located in Appendix C (Tables C.38 and C.81).

3.2.5.2.3 PARTICULATE MATTER (PM/PM₁₀/PM_{2.5}) AND LEAD (Pb), MERCURY (Hg), AND BERYLLIUM (Be) EMISSIONS

The PM/PM₁₀/PM_{2.5} and Pb, Hg, and Be emissions from the flares are conservatively estimated using the same methodology used to calculate these emissions from refinery fuel gas combustion equipment. An example as detailed in Equation 3-19.

Equation 3-19

$$PM / PM_{10} / PM_{2.5} = PH * EF_{AP-42} * \frac{1}{HHV_{AP-42}}$$

Where,

PH = Flare purge heat input rate (MMBtu/hr)

EF_{AP-42} = AP-42 emission factor (lb/MMscf)

HHV_{AP-42} = natural gas higher heating value assumed by AP-42 (MMBtu/MMscf)

The GOHT Flare purge heat input rate is 2.17 MMBtu/hr as calculated in Section 3.2.5.2.1. Therefore, the PM/PM₁₀/PM_{2.5} emissions from the GOHT Flare are:

$$PM \text{ (tpy)} = 2.17 \frac{MMBtu}{hr} * 7.6 \frac{lb}{MMscf} * \frac{1 MMscf}{1,020 MMBtu} * 8,760 \frac{hr}{yr} * \frac{1 ton}{2,000 lb}$$

$$PM \text{ (tpy)} = 0.1 \text{ tpy}$$

The PM/PM₁₀/PM_{2.5} emissions estimates from the new flares are located in Appendix C (Tables C.38 and C.81).

3.2.6 FUGITIVE VOC COMPONENTS

As part of the CXHO project a number of new fugitive emission components (e.g., valves, flanges, pumps, etc.) will be added. Additionally, a number of existing fugitive emission components will be removed in association with the shutdown or modification of some existing process units. Because detailed process and instrumentation diagrams (P&IDs) are not yet available for the new units, the total number of components were estimated based on similar existing units at the refinery or similarly designed units by the same vendor. To add conservatism, an additional 10% contingency factor was then added to the total count. To estimate the VOC emissions increase due to the changes in fugitive emission components at the refinery, EPA screening emission factors (taken from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates) were applied to the estimated number and type of new components. As detailed in Appendix C (Tables C.39 through C.60 and C.81), the gas and light liquid leak detection and repair (LDAR) control efficiencies achieved for pumps and valves are 95% and 80%, respectively based on a 500 ppmv leak definition for valves and 2000 ppmv leak definition for pumps (taken from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates). The remainder of the new fugitive components achieve a 30% control efficiency from audio/visual/olfactory observations (AVO) per Texas Commission on Environmental Quality (TCEQ) Guidance "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" (October 2000). Design details for components are not yet available to speciate the service of each of the new CXHO project components. As a conservative basis, all components were assumed to contain 100% VOC.

The VOC emissions estimates from fugitive components are detailed in Appendix C (Tables C.39 through C.60 and C.81).

3.2.7 TEMPORARY CONCRETE CRUSHER

The PM/PM₁₀/PM_{2.5} emissions from concrete crushing and the two associated transfer points were calculated using EPA's published emission factors in AP-42 from Section 11.19.2, Table 11.19.2-2 (August 2004).

3.3 MODIFIED UNITS

3.3.1 OVERVIEW

In addition to the new units being constructed as part of the CXHO project, BP Whiting will be physically modifying a number of existing units as part of the project. These modified units are identified in Section 2.2.

The project emissions calculations for modified units are discussed in the following sections. Project emissions for modified units are calculated as a comparison of future potential emissions to baseline actual emissions. Note that a similar methodology is applied when evaluating the emissions from other existing emission units at the refinery that are affected by the CXHO project, but not physically modified. These affected existing units are discussed in Section 2.4. The modifications proposed for existing units will improve overall reliability and are anticipated

to reduce emissions from startup, shutdown, and malfunction events. Therefore, the emissions from startup, shutdown, and malfunction events are not included in the net emissions for the CXHO project.

3.3.1.1 BASELINE ACTUAL EMISSIONS

The baseline actual emissions are defined by 326 IAC 2-2-1(e)(2) or 326 IAC 2-3-1(d)(2) for existing emission units other than an electric utility steam generating unit as:

... average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive twenty-four (24) month period selected by the owner or operator within the ten (10) year period immediately preceding either the date the owner or operator begins actual construction of the project or the date a complete permit application is received by the department for a permit required by this rule ...

To determine baseline actual emissions for each NSR regulated pollutant, BP Whiting reviewed annual emissions from 1999 to 2004 to choose a consecutive twenty-four month period for each pollutant. Appendix C provides documentation of the chosen baseline period for each pollutant. The emission factors used to calculate regulated NSR pollutant emissions are derived from stack tests, CEMS data, vendor guaranteed emission rates, permit limits, and/or published emission factors from AP-42 (see Appendix C for a complete listing of the source of emission factors for various units). However, as required by 326 IAC 2-2-1(e)(2)(C) and 326 IAC 2-3-1(d)(2)(C), the baseline actual emissions were adjusted downward to reflect any legally enforceable emission limitation or operating restrictions that currently applies to the unit being modified or affected. This applies, for example, to units like the FCUs that have lower emissions limits established pursuant to the BP Whiting consent decree.⁷ This downward adjustment, if any, is detailed in the emissions documentation of baseline actual emissions provided in Appendix C.

3.3.1.1.1 BACKGROUND BASIS FOR SO₂ BASELINE

Additionally, SO₂ baseline emissions are calculated as described in this section. Historically, BP Whiting has based sulfur dioxide (SO₂) emissions from its combustion sources on CEMS data that measures the amount of hydrogen sulfide (H₂S) in the fuel gas combusted, as required by federal New Source Performance Standards. However, it has been learned that in addition to H₂S there are other types of reduced sulfur compounds in the fuel gas. In 2006 the refinery reported SO₂ emissions in their Annual Emissions Report based on emissions resulting from the combustion of both H₂S and the other sulfur compounds. The primary reduced sulfur compound constituents in fuel

⁷ United States, et. al. v. BP Exploration & Oil, et. Al.; Northern District of Indiana, Hammond Division; Civil Action No. 2:96 CV 095 RL.

gas are H₂S and various mercaptans. The concentration of the other sulfur compounds was determined based on sampling of the fuel gas in 2006.

The SO₂ baseline emissions for 2006 are based on an average TRS concentration of 147 ppmv. Of this value, the non-H₂S portion is about 111 ppmv. BP Whiting has recalculated SO₂ baseline emissions for other years using CEMS measured H₂S data combined with the 111 ppmv of other TRS compounds determined from this sampling. These recalculated emissions remain in compliance with applicable permit limitations.

The presence of other TRS compounds other than H₂S is not unique to BP Whiting. BP Whiting's current TRS data is based on grab samples; the amount of TRS compounds found at Whiting is consistent with TRS values that have been found at other BP refineries. Testing at these refineries showed TRS values ranging between 80 and 200 ppmv.

It is reasonable to expect that there will be some variation in TRS values from one refinery to another. This is due to variations in the size and complexity of the refinery operations. While H₂S is ubiquitous throughout the refinery, the other TRS compounds come primarily from the Coker process unit. The amount of non-H₂S TRS (primarily mercaptans) that remains in fuel gas is a function of the design for the Coker's vapor recovery unit (VRU) where fuel gas and saleable products are separated. The design of the VRU determines the amount of propane in fuel gas and thus the amount of non-H₂S TRS, since the boiling point of some mercaptans compounds is near that of propane. Since the refinery's Coker off-gas is routed to Mix Drum #1 (SRU Mix Drum), only the SO₂ emissions for the heaters that receive fuel gas from Mix Drum #1 (SRU Mix Drum) have been adjusted for TRS.

The H₂S portion of TRS in fuel gas is determined by the refinery's sulfur recovery system which is designed to control acid gases such as H₂S. Refinery fuel gas is scrubbed in an amine contactor to remove H₂S in the gas to typically about 40 ppmv. However, the other TRS compounds, primarily mercaptans, are organic compounds (not acid gases) and are not removed by the sulfur recovery system. Thus, their quantity remains relatively unchanged in the fuel gas after they leave the VRU process.

Regarding the CXHO project, the TRS in fuel gas will be limited to 80 ppmv. This level of TRS is accomplished primarily by building a new VRU for the new Coker process unit. The new VRU is specifically designed to limit the amount to mercaptans in the fuel gas to less than 20 ppmv by reducing propane (and thus mercaptans) in the fuel gas. The H₂S content of the fuel gas will continue to be about 40 ppmv by scrubbing the fuel gas with additional amine contactor capacity. BP Whiting will monitor the total reduced sulfur content of the fuel gas.

3.3.1.1.2 PARTICULATE MATTER (PM₁₀) BASELINE EMISSIONS

The combustion-related baseline actual PM₁₀ emissions for modified process heaters are calculated as shown in Equation 3-1 using the total PM emission factor from EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998). Certain process heaters at BP Whiting have PM₁₀ emissions limits pursuant to the Lake County PM₁₀ SIP (326 IAC 6.8-2-6) (Lake County SIP). In some cases, the Lake County SIP limits are more limiting than the AP-42 emission factor for total particulate emissions. However, it should be noted that the Lake County SIP regulates filterable PM₁₀ emissions only. This is consistent with the compliance demonstration under 326 IAC 6.8-4-1(1) which requires compliance with the PM₁₀ limits to be determined using reference test methods 201/201A for filterable particulate matter only. Using the AP-42 emission factor for filterable particulate emissions, all process heaters at BP Whiting are and were historically in compliance with the PM₁₀ SIP limits. BP believes that the AP-42 emission factor for total PM (i.e. filterable + condensable) should be used to calculate the PM₁₀ baseline emissions for the process heaters since, for PM₁₀ emissions, Major NSR applicability is based on both filterable and condensable particulate matter. Further, no downward adjustments should be necessary for the PM₁₀ baseline actual emissions for the process heaters since the filterable PM₁₀ emissions were in compliance with the PM₁₀ SIP emissions limits. While BP Whiting believes that this is the appropriate method for calculating PM₁₀ baseline actual emissions from modified and existing affected units, BP has conservatively presented the PM₁₀ emissions increases from modified and existing affected units using PM₁₀ baseline emissions adjusted for current PM₁₀ SIP limitations.⁸

The annual average hourly heat input rate for each year during the baseline period is calculated using the annual fuel usage and higher heating value during each year of the baseline period, as shown in Equation 3-20.

Equation 3-20

$$D = FU * HHV_F * \frac{1}{8,760}$$

Where,

D = Average hourly heat input rate during baseline period (MMBtu/hr)

FU = Average annual fuel usage during the baseline period (MMscf/yr)

HHV_F = Average refinery fuel gas higher heating value during the baseline period (MMBtu/MMscf)

⁸ Based on interim guidance from US EPA, PM_{2.5} is evaluated based on significant emission rate thresholds established for PM₁₀. PM_{2.5} emissions are not regulated by the Lake County PM₁₀ SIP, however, to be conservative, BP Whiting has adjusted PM_{2.5} baseline emissions in the same manner as for PM₁₀ emissions.

As an example, the ISOM heater H-1 had annualized fuel usage in 2001 and 2002 of 1,218.56 MMscf/yr and 966.23 MMscf/yr, respectively. The ISOM heater H-1 had average annual fuel gas higher heating values in 2001 and 2002 of 1232.16 MMBtu/MMscf and 1251.2 MMBtu/MMscf, respectively. Therefore, the ISOM heater H-1 average annual heat input rate and PM/PM10/PM2.5 emissions during the baseline period were:

$$D_{ISOM\ H-1} = \frac{2184.79}{2} \frac{MMscf}{yr} * \frac{2438.36}{2} \frac{MMBtu}{MMscf} * \frac{1}{8,760} = 154.70\ MMBtu/hr$$

$$PM_{10}\ Emissions = 154.70\ MMBtu/hr * 0.0075 \frac{lb}{MMBtu} * 8,760 * \frac{1}{2,000} = 5.0\ tpy$$

The annualized PM₁₀ SIP emission limits for the modified units can be located in Appendix C (Table C.84). The PM₁₀ emissions for the combustion sources during the baseline years (2001-2002) can be located in Appendix C (Tables C.14 and C.15).

3.3.1.2 FUTURE POTENTIAL EMISSIONS

Future potential emissions are defined by 326 IAC 2-2-1(nn) or 326 IAC 2-3-1(ii) as:

"Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable as a practical matter. Secondary emissions do not count in determining the potential to emit of a stationary source.

BP Whiting has determined the maximum potential future usage of each modified or affected process unit. Future potential emissions from these units are detailed in Appendix C.

For example, for 11PS heater H-1X, the NO_x net emissions increase is calculated as follows:

Future Potential Emissions [tpy]		126.4
Baseline Emissions (1999-2000) [tpy]	(-)	100.7
Unit Emissions Increase [tpy]		25.7

These calculations are detailed for all emission units in Appendix C Tables C.71 through C.80. The following sections provide some specific examples of emissions calculations for modified emission units.

3.3.2 MODIFIED PROCESS HEATERS

Certain existing process heaters will be modified as part of the CXHO project (either through physical modifications, changes resulting in the de-rating of units or installation of controls). These include 11C H-200, ISOM H-1, and BOU F-401. The future potential heat input capacities and subsequent emissions for these modified heaters are detailed in Appendix C (Table C.11).

3.3.2.1 ISOM H-1

Although undergoing physical modifications as part of the CXHO project, it should be noted that the future potential ISOM H-1 heater heat input capacity will remain below the currently permitted maximum heat input capacity. The future potential NSR regulated pollutant emissions for this unit were calculated using CEMS data, vendor guarantee emission rates, and/or EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998). A complete list of emission factors can be located in Appendix C (Tables C.1 to C.10).

Specifically, the ISOM H-1 heater potential VOC, PM/PM₁₀/PM_{2.5}, CO, NO_x, and Pb emissions are based on EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998) as noted in Appendix C (Tables C.1 to C.10). The methodology for these emission calculations is detailed in Equation 3-1. The potential SO₂ and H₂SO₄ mist emissions were calculated using the methodology detailed in Equations 3-4 and 3-8.

3.3.2.2 11C PS H-200

As part of the CXHO project, BP will install Ultra-Low NO_x burners on the 11 PS H-200 heater to reduce NO_x emissions for the purposes of creating creditable emissions decreases. The potential emissions of VOC, PM/PM₁₀/PM_{2.5}, CO, Pb, SO₂, and H₂SO₄ mist for this heater are calculated using methodologies similar to those described above for the ISOM H-1 heater. Since Ultra-Low NO_x burners will be installed, NO_x emissions from the 11 PS H-200 heater will be calculated based on a vendor guaranteed emission rate using the methodology detailed in Equation 3-2.

3.3.2.3 BOU HEATER F-401

Although undergoing physical modifications as part of the CXHO project, it should be noted that the future potential BOU heater F-401 heater heat input capacity will remain below the currently permitted maximum heat input capacity. The future potential NSR regulated pollutant emissions for this unit were calculated using CEMS data and/or EPA's AP-42 Tables for natural gas combustion Section 1.4 (July 1998). A complete list of emission factors can be located in Appendix C (Tables C.1 to C.10).

3.3.3 MARINE DOCK LOADING

Controls will be installed on the gasoline loading operations at the Marine Dock to reduce future VOC emissions from this operation. The vapor recovery controls will meet an emission rate of 10 mg VOC/L throughput for gasoline loaded, using a vapor recovery, flameless oxidation or low

emissions flare system. The potential VOC emissions from gasoline loading are calculated using Equation 3-21.

Equation 3-21

$$Emissions = Throughput * 42 \frac{gal}{bbl} * 3.785 \frac{L}{gal} * VOC\ EF * \frac{1\ lb}{453,592\ mg}$$

Where,

Throughput = Amount loaded annually (barrels/yr)

VOC EF = Controlled emission factor (10 mg VOC/L throughput)

The projected annual gasoline throughput through the marine dock loading is estimated to be approximately 4,000,000 barrels/yr based on historical data. Therefore, the projected annual VOC emissions from the marine dock loading are:

$$VOC\ (tpy) = 4,000,000 \frac{bbls}{yr} * 42 \frac{gal}{bbl} * 3.785 \frac{L}{gal} * 10 \frac{mg\ VOC}{L} * \frac{1\ lb}{453,592\ mg} * \frac{1\ ton}{2,000\ lb}$$

$$VOC\ (tpy) = 7.0\ tpy$$

The VOC emissions estimates from marine loading, as well as additional NO_x and CO emissions estimates as provided by the system vendor can be located in Appendix C (Table C.61).

3.3.4 COOLING TOWERS

To generate PM/PM₁₀/PM_{2.5} emissions reductions, BP Whiting will install high efficiency drift eliminators, which provide PM/PM₁₀/PM_{2.5} control through reducing liquid drift to 0.001%, on four existing cooling towers (cooling towers 2, 3, and 4). The PM/PM₁₀/PM_{2.5} emissions from the cooling towers can be calculated using the same methodology detailed in Equations 3-10 and 3-11. Table 3.5 details the input parameters, which are based on historical data.

TABLE 3.5 CONTROLLED COOLING TOWER PARAMETERS

Unit	Recirculation Rates (gpm)	TDS (mg/L)
Cooling Tower 2*	25,000	1,627
Cooling Tower 3	90,000	1,147
Cooling Tower 4	44,000	1,645

* Half of the Cooling Tower 2 modules were controlled prior to the CXHO Project. Contemporaneous to the CXHO Project the other modules will be controlled with high efficiency drift eliminators. Note the recirculation rate for Cooling Tower 2 represents half of the total Cooling Tower 2 recirculation rate.

Emissions estimates from cooling towers are located in Appendix C (Table C.26).

3.3.5 FLUIDIZED CATALYTIC CRACKING UNIT 600 (FCU 600)

The FCU 600 main fractionator will be modified as part of the project (refer to Section 2.2.4 for a more detailed discussion of FCU modifications). The potential emission calculations for the NSR regulated pollutants of interest are described below.

3.3.5.1 VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

The FCU 600 VOC emissions are calculated using EPA's published emission factors in AP-42 petroleum refining Section 5.1 (January 1995). The emission calculation methodology is described in Equation 3-22.

Equation 3-22

$$Emission = Throughput * VOC \ EF_{AP-42} * (1 - Eff)$$

Where,

Throughput = Estimated future actual barrels of fresh feed

VOC EF_{AP-42} = Standard AP-42 emission factor

Eff = Pollutant specific control efficiency

The percent efficiency for VOC is 98.5% and is based on a proprietary technology that is used in the catalyst regenerators to promote the combustion of coke to completion. Therefore, the potential annual VOC emissions for FCU 600 are:

$$VOC \ (tpy) = 66 \frac{1000 \ bbl}{day} * 365 \frac{day}{yr} * 220 \frac{lb}{1000 \ bbl} * (1 - \frac{98.5\%}{100}) * \frac{1 \ ton}{2,000 \ lb}$$

$$VOC \ (tpy) = 39.7 \ tpy$$

The projected annual VOC and PM/PM₁₀/PM_{2.5} emissions estimates from the FCU 600 are located in Appendix C (Tables C.64).

3.3.5.2 NITROGEN OXIDE (NO_x) EMISSIONS

The FCU 600 NO_x emissions are calculated using the methodology described in Equation 3-23.

Equation 3-23

$$\text{Emissions (tpy)} = C * \text{coke} \left(\frac{\text{lb Exhaust Gas}}{\text{lb coke}} \right) \left(\frac{\text{MW Pollutant}}{\text{MW Exhaust Gas}} \right) \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

Where,

C = Pollutant concentration (ppmv) at 0% excess oxygen

coke = Total coke burned (lb/yr)

Exhaust Gas (lb):coke (lb) = 11.6 per refinery engineering estimates at 0% excess oxygen

Pursuant to BP Whiting's consent decree, the NO_x concentration for FCU 600 is limited to 20 ppmv at 0% excess oxygen on a 365-day rolling average basis.

The change in feedstocks that will occur with the CXHO project will change the ratio of coke burned per bbl of fresh feed. The future ratio is estimated as 17.8 lb coke burned per bbl of fresh feed. Therefore, the potential pounds of coke burned at the FCU 600 are:

$$\begin{aligned} \text{Coke} \left(\frac{1,000 \text{ lb}}{\text{yr}} \right) &= 66 \frac{1,000 \text{ bbl}}{\text{day}} * 365 \frac{\text{day}}{\text{yr}} * 17.8 \\ \text{Coke} \left(\frac{1,000 \text{ lb}}{\text{yr}} \right) &= 428,802 \frac{1,000 \text{ lb coke burned}}{\text{yr}} \end{aligned}$$

Therefore, the projected NO_x emissions for FCU 600 are:⁹

$$\begin{aligned} \text{NO}_x \text{ (tpy)} &= 20 \text{ ppm} * \frac{428.80 \times 10^6 \text{ lb coke}}{\text{year}} * 11.6 * \left(\frac{31 \text{ lb NO}_x / \text{lbmol}}{31 \text{ lb exhaust gas} / \text{lbmol}} \right) * \frac{1 \text{ ton}}{2,000 \text{ lb}} \\ \text{NO}_x \text{ (tpy)} &= 49.7 \text{ tpy} \end{aligned}$$

The projected annual NO_x emissions estimates from the FCU 600 are located in Appendix C (Tables C.64).

3.3.5.3 SULFUR DIOXIDE (SO₂) EMISSIONS

The FCU 600 SO₂ emissions are based on the methodology described in Equation 3-23, above. As part of the CXHO project, FCU 600 will be operated to achieve an annual average outlet sulfur concentration of 37 ppmv SO₂ (0% oxygen) versus the current limit

⁹ Note that 31 lb/lbmol is used as a weighted average molecular weight for emissions of nitrogen oxides (NO_x).

of 50 ppmv SO₂ (0% oxygen) by hydrotreating all of the feed and using SO₂ reducing additives. Thus, in this application, BP Whiting is requesting that an SO₂ emissions limit of 190 tpy on a 365-day rolling average be established for the FCU 600.

The projected annual SO₂ emissions estimates from the FCU 600 are located in Appendix C (Tables C.64).

3.3.5.4 CARBON MONOXIDE (CO) EMISSIONS

The FCU 600 CO emissions are based on the methodology described in Equation 3-23.

$$CO \text{ (tpy)} = 41 \text{ ppm} * \frac{428.80 \times 10^6 \text{ lb coke}}{\text{year}} * 11.6 * \left(\frac{28 \text{ lb NO}_x / \text{lbmol}}{31 \text{ lb exhaust gas / lbmol}} \right) * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$CO \text{ (tpy)} = 92.1 \text{ tpy}$$

The projected annual CO emissions estimates from the FCU 600 are located in Appendix C (Tables C.64).

3.3.5.5 PARTICULATE MATTER (PM/PM₁₀/PM_{2.5}) EMISSIONS

The FCU 600 PM/PM₁₀/PM_{2.5} emissions are based on an emission factor from a stack test performed in 2005. The PM/PM₁₀/PM_{2.5} emissions can be calculated using Equation 3-25.

Equation 3-25

$$PM / PM_{10} / PM_{2.5} = \text{coke} * EF_{\text{Stack Test}}$$

Therefore, the future proposed PM₁₀/PM_{2.5} emissions from the FCU 600 are:

$$PM / PM_{10} / PM_{2.5} \text{ (tpy)} = \frac{428,802 \times 10^3 \text{ lb coke}}{\text{year}} * 0.35 \frac{\text{lb PM}_{10}/\text{PM}_{2.5}}{10^3 \text{ lb coke}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$PM / PM_{10} / PM_{2.5} \text{ (tpy)} = 75.0 \text{ (tpy)}$$

The projected annual PM/PM₁₀/PM_{2.5} emissions estimates from the FCU 600 can be located in Appendix C (Tables C.64).

3.3.5.6 FUGITIVES AND SEWERS

Additional fugitive components and sewers will be added as part of this project. Emissions from these components are estimated using standard emissions factors and control estimates as noted in Appendix C.

3.4 AFFECTED UNITS

As identified in Section 2.4, many existing units at the refinery are not being physically modified due to the CXHO project, but they are impacted by the project due to the change in crude slate. These units are considered “affected” units and the emissions from these units were evaluated by a similar process as that for the modified units. Baseline actual emissions (adjusted as applicable for current emission limitations) are compared to future potential emissions. The baseline actual emissions were then subtracted from the future potential emissions to determine the net emissions increase and/or decrease for each “affected” unit. Further details of this evaluation are included in Appendix C.

3.5 SHUTDOWN UNITS

Units being shutdown as a result of the CXHO project are identified in Section 2.5 of this application. BP Whiting has included the reduction in actual emissions from the shutdown of these units in the CXHO project net emissions increase calculations. These reductions were based on the baseline actual emissions for these units during the selected 24-month baseline for each pollutant. As necessary, BP Whiting adjusted baseline actual emissions downward in order to account for the incorporation of more stringent limits or emission factors since the baseline period for those units that will be permanently removed from service.

Annual emissions during the baseline years from the shutdown units can be found in Appendix C (Tables C.12 through C.17) for the Coker heaters (11B PS H-101, 102, 103, and 104), 12PS heaters H-2, H-1AS/1AN, H-1B, H-1CX, and H-1CN; Tables C.20 through C.25 for the Beavon-Stretford, SBS Tail Gas Units, and SRU Incinerator; Tables C.27 through C.31 for the SBS Cooling Tower; and Tables C.34 through C.37 for the coke handling system and are detailed below. Emission reductions from the shutdown of these units are provided in Appendix C (Table C.82). Note that additional units (e.g., 1SPS, 3UF, FBI) will be shutdown, unrelated to the CXHO project, but in the contemporaneous period for netting analysis calculations

3.5.1 MATERIAL HANDLING AND STORAGE

The existing coke handling system will be replaced as part of the CXHO Project. The new coke handling system as detailed in Section 2.2.1 was designed to minimize emissions from the coke handling process and results in lower particulate emissions.

Currently, coke is cut out of the coke drums with high pressure water. The wet coke falls out of the drums into piles below the drums where it is transferred by a front-end loader to a staging area for removal of excess water. The coke is transferred via a front-end loader from the staging area to one of two storage piles (3A and 3B). From the two storage piles the coke is loaded onto trucks via a front-end loader for transport off-site. Typically coke is transferred from the staging area into one storage pile while coke is simultaneously loaded into trucks from the other storage pile. Approximately, 100 trucks are loaded per day (five days per week) with approximately 21.5 tons of coke each. Each truck travels 0.8 miles unloaded to the coke yard. Once loaded, each truck is subsequently washed before it transports the coke another 0.8 miles within the refinery from the coke yard to the refinery gate. There are emissions associated with truck traffic both within the vicinity of the coke pile in the coke yard (equivalent to unpaved roads) and on the paved refinery roads between the truck wash and the refinery gate.

Emissions from the existing coke handling system during the baseline period were calculated as detailed below.

3.5.1.1 AGGREGATE STORAGE EMISSIONS

Fugitive emissions from material handling were calculated using Chapter 4 of the 1988 EPA Report "Control of Open Fugitive Dust Sources" (EPA - 450/3-88-008), which uses the formula as shown in Equation 3-26 for wind erosion emissions from continuously active piles.

Equation 3-26

$$\text{PM EF (lb/hr/acre)} = 1.7 \left(\frac{s}{1.5} \right) \left(\frac{365 - p}{235} \right) \left(\frac{f}{15} \right) \left(\frac{1 \text{ day}}{24 \text{ hour}} \right)$$

Where,

s = Silt content of aggregate (%)

p = Number of days with at least 0.01 in. of precipitation per year

f = Percentage of time that the unobstructed wind speed exceeds 12 mph (%)

As provided in the 1988 EPA Report "Control of Open Fugitive Dust Sources", the fraction of total particulate (PM) that is PM₁₀ is estimated at 0.5. This is consistent with the particle size multiplier (k) provided in EPA's AP-42 Section 13.2.5.3 (November 2006). PM_{2.5} emissions were assumed to be equal to PM₁₀ emissions.

Therefore the PM aggregate storage emission factor from the storage piles was calculated in the baseline period as:

$$\text{PM EF (lb/hr/acre)} = 1.7 \left(\frac{4.5\%}{1.5} \right) \left(\frac{365 - 124}{235} \right) \left(\frac{33.4}{15} \right) \left(\frac{1 \text{ day}}{24 \text{ hour}} \right)$$

$$\text{PM EF} = 0.49 \text{ (lb/hr/acre)}$$

The silt content of 4.5% is based on silt content tested a comparable coke handling facility. The number of days with at least 0.01 in. of precipitation per year is based on a 47 year average for Chicago, IL from the National Climate Data Center. The percentage of time that the unobstructed wind speed exceeds 12 mph is based on four years (1997-2001) of metrological data at Midway Airport.

To calculate the PM emissions from aggregate storage, the size of the storage piles was first calculated. The average amount of coke stored in each pile was determined from the daily coke production and number of days per year of coke loading as demonstrated in Equations 3-27 through 3-28. Note that although the coke production process runs continuously, coke loading operations are typically only conducted five days per week. As such, the average pile size is calculated as an annual average number.

Equation 3-27

$$\text{Coke Produced} \left(\frac{\text{ton}}{\text{yr}} \right) = \text{Amount of Coke Produced} \left(\frac{\text{ton}}{\text{day}} \right) * 365 \frac{\text{day}}{\text{yr}}$$

Equation 3-28

$$\text{Average Coke Stored} \left(\frac{\text{ton}}{\text{day}} \right) = \frac{\text{Coke Produced} \left(\frac{\text{ton}}{\text{yr}} \right)}{260 \frac{\text{day}}{\text{yr}}}$$

During the baseline years of 2001-2002 the coke production was 1,638.9 tons of coke per day at 10% moisture content. Therefore, the average coke stored per pile is:

$$\text{Average Coke Stored} \left(\frac{\text{ton}}{\text{day}} \right) = \frac{1,638.9 \left(\frac{\text{ton}}{\text{yr}} \right) * 365 \left(\frac{\text{day}}{\text{yr}} \right)}{260 \frac{\text{day}}{\text{yr}}}$$

$$\text{Average Coke Stored per Pile} = 2,300.8 \frac{\text{ton}}{\text{day}}$$

To calculate the exposed surface area of the pile, the volume of the pile is first calculated using Equation 3-29.

Equation 3-29

$$\text{Volume of Coke Stored} (\text{ft}^3) = \frac{\text{Average Coke Stored} \left(\frac{\text{ton}}{\text{day}} \right) * \frac{2,000 \text{ lb}}{1 \text{ ton}}}{\text{density of coke} \left(\frac{\text{lb}}{\text{ft}^3} \right)}$$

The volume of the coke stored during the baseline period (2001-2002) is calculated using the density of the coke, which is 56 lb/ft³.

$$\text{Volume of Coke Stored} (\text{ft}^3) = \frac{2,300.8 \left(\frac{\text{ton}}{\text{day}} \right) * \frac{2,000 \text{ lb}}{1 \text{ ton}}}{56 \left(\frac{\text{lb}}{\text{ft}^3} \right)}$$

$$\text{Volume of Coke Stored} = 82,171.4 (\text{ft}^3)$$

Since the coke is dropped onto the pile via a front-end loader, the pile is assumed to be cone shaped. The volume of coke stored in each pile is calculated using Equation 3-30.

Equation 3-30

$$\text{Volume of Pile (ft}^3\text{)} = \pi * (r(\text{ft}))^2 * h(\text{ft})$$

which can be re-written as:

$$\text{Radius of Pile} = \sqrt{\left(\frac{3 * \text{Volume of Pile} \left(\frac{\text{ton}}{\text{day}} \right)}{\pi * h(\text{ft})} \right)}$$

The average pile height is approximately 14 ft. Therefore, the radius of the pile during the baseline period was:

$$\text{Radius of Pile} = \sqrt{\left(\frac{3 * 82,171.4 \left(\frac{\text{ton}}{\text{day}} \right)}{\pi * 14(\text{ft})} \right)}$$

$$\text{Radius of Pile} = 74.9(\text{ft})$$

The exposed surface area of the pile can be determined using Equation 3-31.

Equation 3-31

$$\text{Exposed Pile Surface Area (acre)} = \pi * (r(\text{ft}))^2 * \frac{1 \text{ acre}}{43,560 \text{ ft}^2}$$

Therefore, during the baseline period the exposed surface area was:

$$\text{Exposed Pile Surface Area (acre)} = \pi * (74.9(\text{ft}))^2 * \frac{1 \text{ acre}}{43,560 \text{ ft}^2}$$

$$\text{Exposed Pile Surface Area} = 0.40 \text{ acre}$$

Therefore, the PM emissions from aggregate storage for each pile are:

$$\text{PM Emissions} = 0.49 \frac{\text{lb/hr}}{\text{acre}} * \frac{8,760 \text{ hr}}{1 \text{ yr}} * 0.40 \text{ acre} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$\text{PM Emissions} = 0.9 \frac{\text{ton}}{\text{yr}}$$

In addition to wind erosion from the storage piles, there is also wind erosion from the coke yard. The coke yard is covered with a layer of coke, which contributes to particulate emissions. The emissions from the coke yard are calculated using the methodology previously discussed in this section. Note the silt content for the coke yard

is higher due to the pulverization from vehicle traffic within the coke yard. The silt content is estimated to be 10.4% based on silt content testing performed at a comparable coke handling facility. Emission estimates from aggregate storage in the baseline years are located in Appendix C (Table C.34).

3.5.1.2 MATERIAL HANDLING EMISSIONS

Fugitive emissions from material handling were calculated using EPA's published emission factors in AP-42 from Section 13.2.4 (November 2006), which used the empirical formula provided in Equation 3-14.

Emission estimates from material handling in the baseline years are located in Appendix C (Table C.35).

3.5.1.3 FUGITIVE EMISSIONS FROM PAVED ROADS

The existing coke handling system transports coke from the refinery using trucks. However, after the CHXO Project, coke will be transported from the refinery using rail cars. Therefore, the fugitive emissions from paved roads attributable to the truck traffic are eliminated as part of the CXHO Project. Fugitive emissions from paved roads were calculated using EPA's published emission factors in AP-42 from Section 13.2.1 (November 2006), which uses the empirical formula provided in Equation 3-32.

Equation 3-32

$$PM/PM_{10}/PM_{2.5} \text{ EF (lb/VMT)} = \left[k \left(\frac{sL}{2} \right)^{0.65} \left(\frac{W}{3} \right)^{1.5} - C \right] \left(1 - \frac{P}{4N} \right)$$

Where,

k = Particle size multiplier provided in Table 13.2.1-1(lb/Vehicle Miles Traveled (VMT))

sL = Road surface silt loading (g/m²)

W = Average weight of the vehicle traveling the road (tons)

C = Emission factor for 1980's vehicle fleet exhaust, break wear, and tire wear provided in Table 13.2.1-2 (lb/VMT)

P = Number of days with at least 0.01 in. of precipitation during the averaging period

N = Number of days in the averaging period

The road surface silt loading is based on the average silt loading for the most representative industry provided in Table 13.2.1-4 (i.e. the iron and steel production industry). Since the unloaded trucks weighing 15 tons travel 0.8 miles from the refinery gate to the coke yard, and the loaded trucks weighing 36.5 tons travel 0.8 miles from the coke yard to the refinery gate, the average truck weight was estimated to be 25.8 tons. The number of days with at least 0.01 in. of precipitation per year is based on a 47 year average for Chicago, IL from the National Climate Data Center. Additionally, the averaging period is taken to be 365 days. Therefore, the PM emission factor for coke truck traffic on paved roads is:

$$\text{PM EF} = \left[0.082 \frac{\text{lb}}{\text{VMT}} * \left(\frac{9.7 \text{ g/m}^2}{2} \right)^{0.65} * \left(\frac{25.8 \text{ ton}}{3} \right)^{1.5} - 0.00047 \frac{\text{lb}}{\text{VMT}} \right] \left(1 - \frac{124}{4 * 365} \right)$$

$$\text{PM EF} = 5.28 \frac{\text{lb}}{\text{VMT}}$$

The vehicle miles traveled were estimated using the average daily production during the baseline period along with the average amount of coke loaded on each truck as shown in Equation 3-33.

Equation 3-33

$$\text{Vehicle Miles Traveled} \left(\frac{\text{VMT}}{\text{yr}} \right) = \frac{\text{Average Coke Production} \left(\frac{\text{ton}}{\text{day}} \right) * 365 \frac{\text{day}}{\text{yr}}}{\text{Average Coke Loaded on Each Truck} \left(\frac{\text{ton}}{\text{truck}} \right)} * \text{Miles Traveled} \left(\frac{\text{miles}}{\text{truck}} \right)$$

Since the average coke production and coke loaded onto each truck during the baseline period was 1,638.9 ton/day and 21.5 ton/truck respectively, the vehicle miles traveled on paved roads were:

$$\text{Vehicle Miles Traveled} \left(\frac{\text{VMT}}{\text{yr}} \right) = \frac{1,638.9 \left(\frac{\text{ton}}{\text{day}} \right) * 365 \frac{\text{day}}{\text{yr}}}{21.5 \left(\frac{\text{ton}}{\text{truck}} \right)} * 1.6 \left(\frac{\text{miles}}{\text{truck}} \right)$$

$$\text{Vehicle Miles Traveled} \left(\frac{\text{VMT}}{\text{yr}} \right) = 44,518 \text{ (VMT)}$$

Therefore, the PM fugitive emissions from coke truck traffic on paved roads are:

$$\text{PM Emissions} = 44,518 \frac{\text{VMT}}{\text{yr}} * 5.28 \frac{\text{lb}}{\text{VMT}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$\text{PM Emissions} = 117.2 \frac{\text{ton}}{\text{yr}}$$

Emission estimates from material handling in the baseline years are located in Appendix C (Table C.36).

3.5.1.4 FUGITIVE EMISSIONS FROM UNPAVED ROADS

Even though the coke pad is concrete, given the constant coating of the pad with coke dust, the emissions from truck and front end loader traffic within the coke pad are estimated assuming the area is unpaved. This is consistent with the methodology

detailed in EPA's published emission factors in AP-42 from Section 13.2.4.3. Fugitive emissions from unpaved roads were calculated using EPA's published emission factors in AP-42 from Section 13.2.2 (November 2006), which uses the empirical formula provided in Equation 3-34.

Equation 3-34

$$\text{PM}/\text{PM}_{10}/\text{PM}_{2.5} \text{ EF (lb/VMT)} = \left[k \left(\frac{s}{12} \right)^a \left(\frac{W}{3} \right)^b \right] \left(\frac{365 - p}{365} \right)$$

Where,

k = Particle size multiplier provided in Table 13.2.2-2 (lb/VMT)

a and b = Particle size dependant constants provided in Table 13.2.2-2

s = Surface material silt content (%)

W = Mean vehicle weight (tons)

p = Number of days in a year with at least 0.01 in. of precipitation

The silt content was estimated to be 10.4% based on silt content testing done at a comparable coke handling facility. To calculate emissions from truck traffic within the coke yard, the trucks were estimated to travel approximately 360 or 280 feet each way within the coke yard depending on which pile is active (i.e., the total distance can be calculated as the average of these two distances multiplied by two [640 ft] to include the trip into and out of the coke yard). The trucks travel the same distance unloaded weighing 15 tons and loaded weighing 36.5 tons. The number of days with at least 0.01 in. of precipitation per year is based on a 47 year average for Chicago, IL from the National Climate Data Center. Therefore, the PM emission factor for truck emissions on within the coke yard is:

$$\text{PM Emissions} = \left[4.9 \left(\frac{10.4\%}{12} \right)^{0.7} \left(\frac{26.5 \text{ ton}}{3} \right)^{0.45} \right] \left(\frac{365 - 124}{365} \right)$$

$$\text{PM Emissions} = 7.71 \frac{\text{lb}}{\text{VMT}}$$

The truck vehicle miles traveled within the coke yard were estimated using the average daily production during the baseline period along with the average amount of coke loaded on each truck as shown in Equation 3-34.

Equation 3-34

$$\text{VMT} \left(\frac{\text{VMT}}{\text{yr}} \right) = \frac{\text{Average Coke Production} \left(\frac{\text{ton}}{\text{day}} \right) * 365 \frac{\text{day}}{\text{yr}}}{\text{Average Coke Loaded on Each Truck} \left(\frac{\text{ton}}{\text{truck}} \right)} * \text{Ft Traveled} \left(\frac{\text{ft}}{\text{truck}} \right) * \frac{1 \text{ mile}}{5,280 \text{ ft}}$$

Since the average coke production and coke loaded onto each truck during the baseline period was 1,638.9 ton/day and 21.5 ton/truck respectively, the vehicle miles traveled on paved roads were:

$$\text{VMT} \left(\frac{\text{VMT}}{\text{yr}} \right) = \frac{1,638.9 \left(\frac{\text{ton}}{\text{day}} \right) * 365 \frac{\text{day}}{\text{yr}}}{21.5 \left(\frac{\text{ton}}{\text{truck}} \right)} * 640 \left(\frac{\text{ft}}{\text{truck}} \right) * \frac{1 \text{ mile}}{5,280 \text{ ft}}$$

$$\text{VMT} = 3,373 \frac{\text{miles}}{\text{yr}}$$

Therefore, the PM fugitive emissions from truck traffic on within the coke yard are:

$$\text{PM Emissions} = 3,373 \frac{\text{miles}}{\text{yr}} * 7.71 \frac{\text{lb}}{\text{miles}} * \frac{1 \text{ ton}}{2,000 \text{ lb}}$$

$$\text{PM Emissions} = 13.0 \frac{\text{ton}}{\text{yr}}$$

Particulate emissions from the front end loader traffic within the coke yard between the coke piles and the trucks were also calculated. Emission estimates from fugitive dust from truck and front end loader traffic within the coke yard during the baseline years are located in Appendix C (Table C.37).

3.6 SUMMARY OF PROJECT EMISSION INCREASES

CXHO project emissions increases are calculated as the sum of emissions from:

- potential (proposed allowable) emissions from new emission units;
- the emission increases from modified emission units (based on the difference future potential emissions and baseline actual emissions); and
- the emission increases from unmodified but affected existing emission units (i.e., those other existing emission units that BP Whiting has determined will realize associated emissions increases due to the project based on the difference between future potential emissions and baseline actual emissions).

Table 3.6 provides a summary of project emission increases.

TABLE 3.6 PROJECT EMISSION INCREASES FOR PSD POLLUTANTS

Pollutant	NO ₂	SO ₂	PM (filterable)	PM ₁₀ (filterable + condensable)*	CO	Sulfuric Acid Mist	Lead	Mercury	Beryllium	H ₂ S	Total Reduced Sulfur (TRS)
Project Emissions Increase (tpy)	528.1	293.1	138.9	216.7	541.8	12.7	0.04	0.002**	0.0006**	14.8	14.8
PSD Significance Level (tpy)	40	40	25	15	100	7.0	0.6	0.1	0.0004	10	10
Above Significance Level?	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes

*The current PM₁₀ SIP limits filterable PM₁₀ emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM₁₀ baseline based on the PM₁₀ SIP limits for PSD applicability purposes, which includes both filterable and condensable PM₁₀.

** Note that mercury and beryllium are not federally regulated pollutants for PSD purposes. Indiana regulations still list significant emission rates for these pollutants, however this part of the regulation is not SIP-approved by U.S. EPA, therefore this requirement is only state-enforceable.

Project emission increases are estimated to be greater than the PSD significant emission rates for NO₂, SO₂, PM, PM₁₀, CO, sulfuric acid mist, H₂S, TRS, and beryllium. For these pollutants a netting analysis is required to determine if the project will result in a significant net emission increase. BP Whiting has chosen to conduct a netting analysis for all pollutants in order to demonstrate the reductions in emissions realized through the CXHO project.

Since the refinery startup, shutdown, and malfunction emissions are expected to be reduced as a result of the project (due to increased reliability and the use of a flare gas recovery system), no emissions changes from these events have been quantified as part of the project emissions increases.

3.7 NETTING ANALYSIS

For those pollutants for which it has been determined that the project will result in a significant emission increase, a netting analysis is conducted to determine if the project will result in a significant net emission increase.

Per 326 IAC 2-2-1(jj), net emissions increase is defined as follows:

(jj) "Net emissions increase", with respect to any regulated NSR pollutant emitted by a major stationary source, means the following:

(1) The amount by which the sum of the following exceeds zero (0):

(A) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated under section 2(d) of this rule.

(B) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are

- otherwise creditable. Baseline actual emissions for calculating increases and decreases under this clause shall be determined as provided in subsection (e)....*
- (2) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between the following:*
- (A) The date five (5) years before construction of the particular change commences.*
 - (B) The date that the increase from the particular change occurs.*
- (3) An increase or decrease in actual emissions is creditable only if:*
- (A) the department has not relied on the increase or decrease in actual emissions in issuing a permit to the source under 40 CFR Part 52.21* or this rule and the permit is in effect when the increase in actual emissions from the particular change occurs....*
- (4) An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.*
- (5) An increase in actual emissions is creditable only to the extent that a new level of actual emissions exceeds the old level.*
- (6) A decrease in actual emissions is creditable only to the extent that:*
- (A) the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;*
 - (B) it is enforceable as a practical matter at and after the time that actual construction on the particular change begins;*
 - (C) it has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and*
 - (D) the decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a clean unit under 326 IAC 2-2.2-2 or 326 IAC 2-3.2-2. Once an emissions unit has been designated as a clean unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the clean unit designation is based on in calculating the net emissions increase for another emissions unit. However, any new emission reductions that were not relied upon in a PCP excluded under 326 IAC 2-2.3-1 or for a clean unit designation are creditable to the extent they meet the requirements in 326 IAC 2-2.3-1(g)(4) for the PCP and 326 IAC 2-2.2-1(h) and 326 IAC 2-2.2-2(j) for a clean unit.*
- (7) An increase that results from the physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period not to exceed one hundred eighty (180) days...*

3.7.1 CONTEMPORANEOUS PERIOD

As the CXHO project would result in a significant emissions increase, BP Whiting has the option to attempt to “net out” by considering contemporaneous increases and decreases. To make this determination, the contemporaneous period must be defined. 326 IAC 2-2-1(jj)(2) defines the contemporaneous period as follows:

An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between the following:

(A) The date five (5) years before construction of the particular change commences.

(B) The date that the increase from the particular change occurs.

Per 326 IAC 2-2-1(jj)(7), the timing of the particular change is defined as follows:

An increase that results from the physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period not to exceed one hundred eighty (180) days.

This timing also becomes important in terms of determining when contemporaneous decreases must occur in order to be considered creditable. Per 325 IAC 2-2-1(jj)(6),

*A decrease in actual emissions is creditable only to the extent that...
...it is enforceable as a practical matter at and after the time that actual construction on the particular change begins;*

For a decrease to be enforceable at the time construction begins, it must be part of the federally enforceable source modification issued for the change. The timing of when the decrease occurs will also become a condition of the federally enforceable source modification. BP Whiting understands that the requirement for PSD non-applicability is that there is no significant net emissions increase for a project. BP Whiting proposes that the CXHO project source modification, when issued, contain a federally enforceable provision requiring that BP conduct a periodic calculation to track project emissions increases and decreases as well as contemporaneous changes during the project construction period in order to demonstrate that, at no time, does the CXHO project result in a significant net emissions increase. BP Whiting believes this approach is suitable to meet all applicability requirements while dealing with the issues resulting from a large project planned to be completed over a multi-year period.¹⁰ Therefore, BP Whiting is considering the contemporaneous period to encompass the entire timeframe from 2003 (i.e., 5 years prior to the commencement of construction) through 2011 (i.e., when the entirety of the project is anticipated to reach normal operation). BP Whiting has developed an estimated project schedule that includes project milestones for the physical changes as relating to the CXHO project such that there will be no significant emissions increase at any time during the project for any pollutants. However, in order to accommodate potential changes in project schedule, BP proposes that a periodic emissions tracking requirement, rather than enforceable dates for certain project construction events, is the appropriate means to demonstrate compliance.

¹⁰ This approach has previously been discussed with IDEM and US EPA Region 5. There is precedent for this approach including an EPA Guidance memo from Bruce D. Buckheit, Director of Air Enforcement Division to Ms. Linda Korn Levy (Louisiana DEQ) [December 23, 2004].

3.7.2 NET EMISSIONS INCREASE DETERMINATION

Table 3.7 contains the calculated net emissions increases for the project as compared to PSD significant emission rates.

TABLE 3.7 PSD NET EMISSIONS INCREASES

Pollutant	NO ₂	SO ₂	PM (filterable)	PM ₁₀ (filterable + condensable)*	CO	Sulfuric Acid Mist	Lead	Mercury	Beryllium	H ₂ S	Total Reduced Sulfur (TRS)
Net Emissions Increase (tpy)	-28.9	-39.4	-281.9	-41.6	-23.7	-113.4	-0.02	-0.001	-0.005	-15.9	-76.1
PSD Significance Level (tpy)	40	40	25	15	100	7.0	0.6	0.1**	0.0004**	10	10

* The current PM₁₀ SIP limits filterable PM₁₀ emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM₁₀ baseline based on the PM₁₀ SIP limits for PSD applicability purposes, which includes both filterable and condensable PM₁₀.

**Note that other PSD pollutants including asbestos, vinyl chloride, and fluorides have not been included since these pollutants are not emitted from typical refinery process operations, or otherwise considered negligible. Note that mercury and beryllium are not federally regulated pollutants for PSD purposes. Indiana regulations still list significant emission rates for these pollutants, however this part of the regulation is not SIP-approved by U.S. EPA, therefore this requirement is only state-enforceable.

Detailed emissions and netting calculations are provided in Appendix C. As shown in Table 3.7, the CXHO project will not trigger PSD for any criteria pollutant, and therefore no Best Available Control Technology review or dispersion modeling air quality analysis is required.

3.8 NONATTAINMENT NEW SOURCE REVIEW

The BP Whiting Refinery is an existing major stationary source for the purposes of nonattainment new source review for the 8-hour ozone standard (regulated through VOC and NO_x emissions as precursors) and PM_{2.5}. Assessment of project applicability to nonattainment new source review permitting is conducted in a similar fashion to that for PSD applicability (outlined in Section 3.1 of this application) per the requirements of 326 IAC 2-3. Table 3.8 contains the net emissions increases for the CXHO project as compared to significant emission rates for nonattainment pollutants.

TABLE 3.8 NONATTAINMENT NEW SOURCE REVIEW NET EMISSIONS INCREASES

Pollutant	NO_x*	VOC (8-hour Standard)	PM_{2.5} (filterable + condensable) **
Net Emissions Increase (tpy)	-28.9	-6.3	-41.6
Nonattainment NSR Significance Level (tpy)	40	40	15

* Note that for the 1-hour ozone standard, NO_x is not considered an ozone precursor due to the waiver under Section 182(f) of the Clean Air Act. NO_x information is presented here only for the purposes of an evaluation with respect to the 8-hour ozone standard.

**Based on interim guidance from US EPA, PM_{2.5} is evaluated based on significant emission rate thresholds established for PM₁₀. The current PM₁₀ SIP limits filterable PM10 emissions and compliance is based on reference test method 201A (which only quantifies filterable particulate matter). Although not required, BP Whiting has conservatively adjusted the PM₁₀ baseline based on the PM₁₀ SIP limits for PSD applicability purposes, which includes both filterable and condensable PM₁₀. PM_{2.5} emissions are not regulated by the Lake County PM₁₀ SIP, however, to be conservative, BP Whiting has adjusted PM_{2.5} baseline emissions in the same manner as for PM₁₀ emissions.

As shown, net emissions increases are below major modification thresholds for nonattainment new source review.

3.9 NONATTAINMENT NEW SOURCE REVIEW FOR 1-HOUR OZONE STANDARD

Lake County is currently designated as moderate nonattainment for the 8-hour ozone standard. Lake County was previously designated as a severe nonattainment area based on the 1-hour ozone standard. Due to recent court decisions and IDEM guidance, facilities must defer to the NSR program under the one hour standard for processing current applications. The proposed source modification project at the Whiting Refinery will therefore be subject to the de minimis test for nonattainment new source review for ozone (VOC emissions) under 326 IAC 2-3 since the revisions to 326 IAC 1-4 adopting the federal revocation of the 1-hour ozone standard have been reversed by a federal court of appeals decisions considering non-attainment NSR as a control measure in the attainment planning.¹¹ Per 326 IAC 2-3-1(q), a de minimis increase of VOC from a modification in a serious or severe ozone nonattainment area, means an increase that does not exceed twenty-five (25) tons per year when the net emissions increases from the proposed source modification project are aggregated on a pollutant specific basis with all other net emissions increases from the source over a five (5) consecutive calendar year period prior to, and including, the year of the modification.¹² This modification is expected to commence operation in 2011, and therefore the net emissions changes from projects taking place between 2007 and 2011 have been considered for this evaluation.

A summary of net emissions increases from the year of startup of the project and the 4 preceding calendar years is provided in Appendix C (Table C.84). This includes all known contemporaneous projects that will occur from 2007 through 2011. Table 3.9 contains the net emissions increases for the CXHO project as compared to significant emission rates for nonattainment pollutants.

¹¹ Per 326 IAC 2-3-1(ss) "Source modification project" means all those physical changes or changes in the methods of operation at a source that are necessary to achieve a specific operational change.

¹² 326 IAC 2-3-1(dd)(2)

TABLE 3.9 1-HOUR OZONE STANDARD NONATTAINMENT NEW SOURCE REVIEW NET EMISSIONS INCREASES

Pollutant	VOC (1-hour Standard)*
Net Emissions Increase (tpy)	-14.8
Nonattainment NSR Significance Level (tpy)	25

* Note that for the 1-hour ozone standard, NO_x is not considered an ozone precursor due to the waiver under Section 187(f) of the Clean Air Act. NO_x information is presented here for the purposes of an evaluation with respect to the 8-hour ozone standard. VOC emissions are evaluated based on the NSR program effective under the 8-hour ozone standard (Table 3.8) as well as that previously effective under the 1-hour ozone standard for Lake County (Table 3.9).

3.10 HAZARDOUS AIR POLLUTANT EMISSIONS

Overall, Hazardous Air Pollutant (HAP) emissions are anticipated to decrease as the result of this project. As with a typical refinery, the majority of HAP emissions are emissions of organic HAP (e.g., benzene, toluene, ethylbenzene, and xylene, etc.), which are directly related to VOC emissions. A significant source of these emissions is the marine loading dock at the refinery. As part of the CXHO project, HAP emissions from gasoline loading operations at the marine loading dock will be controlled. The resulting significant reduction in VOC and HAP emissions will have the effect of reducing organic HAP emissions refinery-wide; thus, there will be no increase in HAP emissions from the CXHO project.

4. REGULATORY APPLICABILITY ANALYSIS

The applicability of various other federal and state regulations to the CXHO project is discussed in this section.

4.1 COMPLIANCE ASSURANCE MONITORING (CAM)

CAM requirements are typically triggered upon Title V permit renewal. BP Whiting received its initial Title V permit effective January 1, 2007. As such, CAM requirements could only be triggered at this stage by a significant modification to a large pollutant specific emission unit (PSEU).¹³ A large PSEU is a controlled unit for which controlled potential emissions are by themselves above major source permitting thresholds.¹⁴ Units are exempt from CAM if they already are subject to continuous monitoring requirements (e.g., as part of a MACT standard).¹⁵ Note that no units at the refinery meet the definition of a large PSEU as all controlled units that are not subject to continuous monitoring requirements per MACT, have post-control emissions below major source thresholds. CAM requirements are, therefore, not applicable to the CXHO project.

4.2 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

NSPS regulations (codified under 40 CFR Part 60) require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable provisions. The NSPS subparts potentially applicable to the proposed refinery modifications are addressed below.

4.2.1 NSPS SUBPART A – GENERAL PROVISIONS

Any source subject to a source-specific NSPS is also subject to the general provisions of NSPS Subpart A. Unless specifically excluded by the source-specific NSPS, Subpart A generally requires initial construction/reconstruction notification, initial startup notification, performance tests, performance test date initial notification, general monitoring requirements, general recordkeeping requirements, and semiannual monitoring system and/or excess emission reports.

4.2.2 NSPS SUBPART GGG – EQUIPMENT LEAKS OF VOC IN PETROLEUM REFINERIES

New fugitive components installed at all new and certain modified process areas as part of the CXHO project will be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG. Note that NSPS GGG requirements incorporate by reference the LDAR requirements of NSPS VV. Upon completion of final design specifications, BP will review and determine the applicability of Subpart GGG to each modified process area.

¹³ Per 40 CFR 64.5(a).

¹⁴ Per 40 CFR 64.1

¹⁵ Per 40 CFR 64.2

4.2.3 NSPS SUBPART J – PETROLEUM REFINERIES

NSPS J regulates emissions from fuel gas combustion devices, fluidized catalytic cracking units and sulfur recovery units. All new and modified process heaters under the CXHO project will be subject to the requirements for fuel gas combustion devices under NSPS J. Under these requirements, BP will be required to continuously monitor the H₂S concentration of the refinery fuel gas combusted in these heaters to demonstrate compliance with a limitation of 0.1 gr/scf H₂S in fuel gas (3-hour average). The three new flares constructed as part of the CXHO project will also be subject to this limitation as fuel gas combustion devices.

The FCU 500 and FCU 600 will not trigger the requirements of NSPS J as part of the CXHO project. The affected facility under NSPS J requirements for fluidized catalytic cracking units is the FCU regenerator. The FCU regenerators are not being modified as part of the CXHO project.

The FCU Flare will not be modified as part of the CXHO project; therefore, the FCU Flare will not trigger the requirements of NSPS J.

The new two Claus sulfur recovery unit trains and corresponding COTs will be subject to the sulfur recovery unit requirements under NSPS J. Per these requirements, BP will continuously monitor SO₂ emissions from the COTs in order to demonstrate compliance with a 250 ppmv SO₂ limit.

4.2.4 NSPS SUBPART K – STORAGE VESSELS FOR PETROLEUM LIQUIDS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JUNE 11, 1973, AND PRIOR TO MAY 19, 1978

NSPS K will not be triggered by this project as the CXHO project falls outside the applicable range of dates for commencing construction/modification.

4.2.5 NSPS SUBPART KA – PETROLEUM LIQUIDS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER MAY 18, 1978, AND PRIOR TO JULY 23, 1984

NSPS Ka will not be triggered by this project as the CXHO project falls outside the applicable range of dates for commencing construction/modification.

4.2.6 NSPS SUBPART KB – PETROLEUM LIQUIDS FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JULY 23, 1984

A number of new storage tanks will be constructed as part of the CXHO project. However, based on the vapor pressure properties of the materials to be stored in these tanks, they will not trigger the control or monitoring requirements of NSPS Kb.

4.2.7 NSPS SUBPART QQQ – VOC EMISSIONS FOR PETROLEUM REFINERY WASTEWATER SYSTEMS

There will be new sewers and process drain systems constructed as part of the CXHO project that will be subject to the requirements of NSPS QQQ. Upon completion of final design

specifications, BP will review and determine the applicability of Subpart QQQ to each modified process area.

4.2.8 NSPS SUBPART UU – ASPHALT PROCESSING AND ASPHALT ROOFING MANUFACTURE

The CXHO project will not involve the construction or modification of any storage tanks or process units related to asphalt operations at the refinery. NSPS UU will not be triggered by the CXHO project.

4.2.9 NSPS SUBPART VV – EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY

New fugitive components installed at new and certain modified process areas as part of the CXHO project will be subject to the Leak Detection and Repair (LDAR) requirements of NSPS GGG. Note that NSPS GGG requirements incorporate by reference the LDAR requirements of NSPS VV. Upon completion of design specifications, BP will review and determine the applicability of Subpart GGG to each modified process area.

4.3 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

NESHAPs are federal regulations that apply to sources of HAP. Both 40 CFR 61 (pollutant-specific) and 40 CFR 63 (category-specific) NESHAPs are discussed in this section.

4.3.1 40 CFR 61 NESHAP

The NESHAP subparts found in 40 CFR 61 are pollutant specific regulations applicable to certain sources of HAP. Those 40 CFR 61 NESHAP subparts that potentially apply to the proposed refinery modifications are addressed below.

4.3.1.1 40 CFR 61, SUBPART A – GENERAL PROVISIONS

General requirements under 40 CFR 61 Subpart A are applicable as the refinery is subject to other subparts under 40 CFR 61.

4.3.1.2 40 CFR 61, SUBPART M – ASBESTOS

Construction activities under the CXHO project may be subject to notification and other requirements under 40 CFR 61 Subpart M.

4.3.1.3 40 CFR 61, SUBPART FF – BENZENE WASTE OPERATIONS

The Whiting Refinery is currently subject to 40 CFR 61 Subpart FF with a Total Annual Benzene (TAB) generation greater than 10 Mg/yr. As such, the refinery is subject to control and treatment requirements under 40 CFR 61 Subpart FF. Construction of new and modification of existing process units may alter existing benzene waste streams as well as generate new benzene waste streams. New tank (T-5052) and the new brine treatment system tanks will contain benzene waste water and be subject to 40 CFR 61,

Subpart FF. BP will be required to update the TAB, and install additional controls, as appropriate and required.

4.3.2 40 CFR 63 NESHAP

The NESHAP subparts found in 40 CFR 63 are source category specific regulations applicable to certain sources of HAP. 40 CFR 63 NESHAPs are emission standards for HAP and are generally only applicable to major sources of HAP. 40 CFR 63 NESHAP allowable emission limits are established on the basis of a Maximum Achievable Control Technology (MACT) determination for a particular major source. A HAP major source is defined as having potential emissions in excess of 25 tpy for total HAP and/or potential emissions in excess of 10 tpy for any individual HAP. These NESHAPs apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112[d]) or on a case-by-case basis (Section 112[g]) for facilities not regulated as a specific industrial source type. Those 40 CFR 63 NESHAP subparts that potentially apply to the proposed refinery modifications are addressed below.

4.3.2.1 40 CFR 63, SUBPART A – GENERAL PROVISIONS

Any source subject to a source-specific NESHAP under 40 CFR 63 is also subject to the general provisions of 40 CFR 63 Subpart A. Unless specifically excluded by the source-specific NESHAP, Subpart A generally requires initial notifications, performance tests, general monitoring requirements, general recordkeeping requirements, startup/shutdown/malfunction requirements, and semiannual reports.

4.3.2.2 40 CFR 63, SUBPART Y – MARINE TANK VESSEL TANK LOADING OPERATIONS

The refinery is not currently subject to 40 CFR 63 Subpart Y based on the amount of loading throughput and current HAP emissions. Loading throughput is not anticipated to increase with the CXHO project and BP will be installing additional controls on the loading operations to further reduce emissions. As a result, 40 CFR 63 Subpart Y will not be triggered by the CXHO project.

4.3.2.3 40 CFR 63, SUBPART CC – PETROLEUM REFINERIES

The refinery is currently an existing source under 40 CFR 63 Subpart CC. Requirements include LDAR requirements, control and monitoring requirements for wastewater, storage tanks and process vents. Applicable units constructed as part of the CXHO project will also be subject to these requirements. Note that an affected facility under 40 CFR 63 Subpart CC is defined as the entire refinery, therefore, the CXHO project will not constitute a “reconstruction” of the affected source. As such, new units constructed as part of the CXHO project will be subject to the same existing source standards already applicable to the refinery.

4.3.2.4 40 CFR 63, SUBPART EEE – HAZARDOUS WASTE COMBUSTORS

40 CFR 63 EEE is not triggered by the CXHO project as the only potentially subject source (the existing Fluid Bed Incinerator) is not being modified as part of this project.

4.3.2.5 40 CFR 63, SUBPART UUU – PETROLEUM REFINERIES

The refinery currently operates process units regulated as existing sources under 40 CFR 63 Subpart UUU. Subpart UUU regulates the FCU 500 and FCU 600, the existing sulfur plant, and existing continuous catalytic reformers. The new sulfur recovery units and tail gas units constructed as part of the CXHO project will be subject to the requirements of Subpart UUU (as new units).

4.3.2.6 40 CFR 63, SUBPART EEEE – ORGANIC LIQUIDS DISTRIBUTION

It is not anticipated that any subject equipment will be constructed at the refinery as part of the CXHO project. This applicability will be reviewed as needed.

4.3.2.7 40 CFR 63, SUBPART ZZZZ – STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

It is not anticipated that any subject engines will be constructed at the refinery as part of the CXHO project. This applicability will be reviewed as needed.

4.3.2.8 40 CFR 63, SUBPART DDDDD – INDUSTRIAL, COMMERCIAL, AND INDUSTRIAL BOILERS AND PROCESS HEATERS

The regulations of 40 CFR 63, Subpart DDDDD have been vacated as of the time of submission of this application. IDEM has not adopted an interim regulation, and therefore the requirements of 40 CFR 63, Subpart DDDDD are not addressed in this application. It is assumed that once a replacement regulation is promulgated, all boilers and heaters which would have been subject to 40 CFR 63, Subpart DDDDD will be subject to the replacement.

BP requests that, as part of this permitting action, all references to 40 CFR 63 DDDDD applicability and requirements be removed from the Title V permit.

4.4 INDIANA STATE REGULATIONS

This project is being permitted under the regulations contained in Title 326 of the Indiana Administrative Code (IAC). Indiana air rules fall under two main categories: those regulations that are generally applicable (e.g., permitting requirements) and those that have specific applicability (e.g., particulate matter limits for Lake County sources). The generally applicable requirements are straightforward (e.g., filing of emission statements) and, as such, are not discussed in further detail in this application. Specific requirements applicable to this project are addressed in the following sections. Specific regulations which have been determined to be not applicable to the project are also discussed.

4.4.1 326 IAC 1-6-3 – PREVENTIVE MAINTENANCE PLANS

Preventive Maintenance Plans (PMPs) are required for any source that requires a permit. As such, BP Whiting will develop and maintain PMPs for all new and modified units as part of the CXHO Project.

4.4.2 326 IAC 1-7 – STACK HEIGHT PROVISIONS

The stack height provisions in this rule apply to sources for which construction commenced after June 19, 1979 and that emit SO₂ or PM emissions in levels greater than 25 tpy. The following units associated with the CXHO Project are subject to these requirements:

COT 1
COT 2
Hydrogen Plant Heater HU-1
Hydrogen Plant Heater HU-2

The exhaust stacks serving these sources will meet the height provisions listed in 326 IAC 1-7-3 or comply with noted alternatives.

4.4.3 326 IAC 2-2 – PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REQUIREMENTS

The CXHO Project is not subject to the provisions of 326 IAC 2-2 since the project's net emissions increase is below the PSD significant emissions rate threshold for all pollutants. See Section 3 for more detail.

4.4.4 326 IAC 2-3 – EMISSION OFFSET

The requirements in this rule do not apply to the CXHO Project since the project net emissions increase for nonattainment pollutants (NO_x, VOC, and PM_{2.5}) are below the corresponding NSR significant emissions rate. See Section 3 for more detail.

4.4.5 326 IAC 2-7-10.5 AND 326 IAC 2-7-12 MINOR NEW SOURCE REVIEW AND MODIFICATION TO TITLE V PERMIT

This project is subject to the requirement to obtain a significant source modification per 326 IAC 2-7-10.5(f)(4) and (7). In addition, since significant changes to the Title V permit will need to be made to include the new units and modifications, a significant permit modification is required per 326 IAC 2-7-12(d)(1).

4.4.6 326 IAC 3-5 – CONTINUOUS MONITORING OF EMISSIONS

BP Whiting is subject to continuous emissions monitoring requirements in this rule and will meet the requirements of the rule for applicable units, as required.

4.4.7 326 IAC 5-1-2 – OPACITY LIMITS

This rule requires facilities in Lake County to meet the following facility-wide opacity limits:

- Opacity shall not exceed 20% in any six-minute period, and
- Opacity shall not exceed 60% in any cumulative total of fifteen (15) minutes in any 6-hour average period.

BP Whiting is subject, and will comply, with the facility-wide opacity limits in this rule.

4.4.8 326 IAC 6.8-1-2, 6.8-2-6 – LAKE COUNTY PM/PM₁₀ EMISSION REQUIREMENTS

BP Whiting is subject to the PM/PM₁₀ limits in these rules. Specifically, PM₁₀ emissions from the new units constructed as part of the CXHO Project will be limited to 0.03 gr/dscf, as required by 326 IAC 6.8-1-2 (based on the U.S. EPA Method 5 reference test method). BP will demonstrate compliance with these emissions limits consistent with the methods noted in the regulation. Units modified and affected as part of the CXHO project may be currently subject to unit-specific emissions limits in 326 IAC 6.8-2-6. In a letter dated February 24, 2006, BP Whiting submitted to IDEM a request to revise the PM₁₀ SIP limits in 326 IAC 6.8-1-2 in order to incorporate updated limits for certain existing units. This request is currently undergoing review. BP Whiting will maintain compliance with the unit-specific emission limits identified in the February 24, 2006 letter or will amend the request to modify the limits set per 326 IAC 6.8-2-6, if necessary. BP is and will be in compliance with the currently applicable emission limits based on the test method specified in the rule.

4.4.9 326 IAC 6.8-8-1 – LAKE COUNTY OPACITY/PM PLAN

As required by this rule, BP Whiting is required to develop and maintain a continuous compliance plan for opacity and PM. BP Whiting will update this plan to incorporate new emission units, as needed.

4.4.10 326 IAC 6.8-10-3 – LAKE COUNTY FUGITIVE PARTICULATE MATTER

BP Whiting is subject to, and will comply with, the fugitive particulate matter requirements in this rule.

4.4.11 326 IAC 6-3-2 – PARTICULATE EMISSION LIMITATIONS FOR MANUFACTURING PROCESSES

This rule includes process weight rate limits for particulate matter. While most CXHO project associated emissions units are subject to county-specific or unit-specific particulate matter regulations, the requirements in this rule will apply to the new and modified coke handling operations.

4.4.12 326 IAC 6-4 – FUGITIVE DUST EMISSIONS

The fugitive dust emissions limits are applicable to BP Whiting. As such, BP Whiting will comply with the fugitive dust limits in this rule.

4.4.13 326 IAC 7-1.1-1, 7-2, 7-4.1-3 – LAKE COUNTY SO₂ EMISSION LIMITATIONS

This rule identifies unit-specific SO₂ emissions limits for BP Whiting's operations. For existing units being modified as part of the CXHO Project, BP Whiting will maintain compliance with established limits.

It should be noted that the new units being installed as part of the CXHO project will not be subject to the limitations per 326 IAC 7-4.1-1 since the potential SO₂ emissions from these units

are below the 25 tpy applicability threshold specified in 326 IAC 7-1.1-1 or the units fire natural gas.

4.4.14 326 IAC 8-1-6 – VOC RULES, BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

In this rule, IDEM requires every new unit that has potential emissions greater than 25 tpy of VOC to perform a BACT review. Since none of the CXHO project new units has potential emissions greater than 25 tpy of VOC, this rule is not applicable.

4.4.15 326 IAC 8-4-2 – VOC RULES, PETROLEUM SOURCES – REFINING SOURCES

This rule applies to vacuum producing systems, wastewater separators, and process unit turnarounds. BP Whiting is subject to the requirements identified in this rule and will comply, as required.

4.4.16 326 IAC 8-4-3 – VOC RULES, PETROLEUM SOURCES – PETROLEUM LIQUID STORAGE VESSELS

As part of the CXHO Project, BP Whiting is installing a number of new storage tanks. These tanks will be used to store materials with true vapor pressures less than 1.52 pounds per square inch (psi), therefore, they will be exempt from the requirements in this rule.

4.4.17 326 IAC 8-4-4 – VOC RULES, PETROLEUM SOURCES – BULK GASOLINE TERMINALS

This rule specifies VOC control requirements for bulk gasoline terminals. The CXHO Project does not impact the refinery bulk gasoline terminal operations. However, BP Whiting will ensure its existing operations continue to comply with these requirements.

4.4.18 326 IAC 8-4-5 – VOC RULES, PETROLEUM SOURCES – BULK GASOLINE PLANTS

This rule specifies VOC control requirements for bulk gasoline plants. Since the Whiting Refinery is not considered a bulk gasoline plant, the requirements in this rule are not applicable.

4.4.19 326 IAC 8-4-6 – VOC RULES, PETROLEUM SOURCES – GASOLINE DISPENSING FACILITY

This rule specifies VOC control requirements for gasoline dispensing facilities. The CXHO Project does not impact its gasoline dispensing operations. However, BP Whiting will ensure its existing operations continue to comply with these requirements.

4.4.20 326 IAC 8-4-7 – VOC RULES, PETROLEUM SOURCES – GASOLINE TRANSPORT

This rule specifies VOC control requirements for gasoline transport operations. The CXHO Project does not impact its gasoline transport operations. However, BP Whiting will ensure its existing operations continue to comply with these requirements.

4.4.21 326 IAC 8-4-8, 8-4-9 – VOC RULES, PETROLEUM SOURCES – LEAK MONITORING AND DETECTION

BP Whiting is subject to the leak monitoring and detection requirements in these rules.

4.4.22 326 IAC 8-7-3 –LAKE COUNTY VOC REDUCTION MEASURES

This rule requires affected sources to reduce baseline actual VOC emissions by 98%, or by 81% if 98% is technologically or economically infeasible, by May 31, 1995, or meet RACT requirements approved by U.S. EPA and IDEM. Since BP Whiting is located in Lake County, it is subject to these general VOC reduction measures. However, the CXHO Project itself is not subject to these rules, since corresponding new or modified units are instead subject to 326 IAC 8-4 requirements.

4.4.23 326 IAC 8-7-10 –LAKE COUNTY VOC CONTROL DEVICE MONITORING REQUIREMENTS

Monitoring requirements identified in this rule apply to sources in Lake County. However, the monitoring requirements do not apply to petroleum sources covered by 326 IAC 8-4. As such, the CXHO Project is not subject to this rule.

4.4.24 326 IAC 8-9-4 –VOLATILE ORGANIC LIQUID STORAGE VESSEL REQUIREMENTS

This rule includes requirements for storage tanks that contain volatile organic liquids and are located in Lake County. Since all the new storage tanks containing volatile organic liquids to be constructed as part of the CXHO project will contain materials with vapor pressures below 0.75 psi, they are exempt from the monitoring and control requirements in this rule. The record keeping requirements will apply to all new tanks containing volatile organic liquids.

4.4.25 326 IAC 9-1-2 – CO EMISSION LIMITATIONS

Control requirements for CO emissions from catalyst regeneration petroleum cracking systems and petroleum fluid cokers are established in this rule. Exemptions from this rule include those units that are subject to NSPS or NESHAP requirements. The cracking units at the refinery are subject to NESHAP requirements and will be exempt from these requirements. The new coker being constructed as part of the CXHO project will be a delayed coker, not a fluid coker, and is therefore not subject to these requirements.

4.4.26 326 IAC 10-4-2 –NO_x BUDGET TRADING PROGRAM

The NO_x Budget Trading Program is applicable to large affected units.

Per 326 IAC 10-4-2(77),

(71) “Unit” means a fossil fuel-fired:

- (A) stationary boiler;
- (B) combustion turbine; or
- (C) combined cycle system.

No new turbines or combined cycle systems will be constructed as part of the CXHO project. Note that a number of process heaters will be constructed as part of this project, but process heaters do not meet the definition of boiler per 326 IAC 10-4-2(77):

(6) “Boiler” means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other heat transfer medium.

Process heaters are used to provide indirect heating to materials to be used in the process and not to heat a heat transfer medium such as steam. As such, process heaters are not subject to this program.

The Whiting Refinery operates existing boilers that are subject to the NO_x Budget Program and will continue to meet applicable requirements for those units. As discussed in Appendix E, the new boilers will be required to comply with the CAIR requirements in 326 IAC 24-3.

4.5 FUTURE REGULATIONS

Since future regulations are expected to become applicable during the period of construction and permitting, BP requests that a compliance plan and schedule be included in the permit to address applicability for these future regulations such that the permit will not need to be reopened. Specifically, if and when the following regulations become final, they will be apply to affected facilities at the refinery: 40 CFR 60, Subpart Ja; 40 CFR 60, Subpart GGGa; and 40 CFR 63, Subpart DDDDD.

APPENDIX A

PROCESS FLOW DIAGRAMS

AREA MAP

PLOT PLAN

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TANKS 4.0 OUTPUT

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E.1.3 11C Pipestill TAR

E.1.4 FCU 600 WARP

E.1.5 FCU 500 TAR

E.1.6 FCU 500 WARP

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E.1.8 Fire Pump Engines

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E.2 – Process Flow Diagrams

E.3 – Emissions Calculations

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